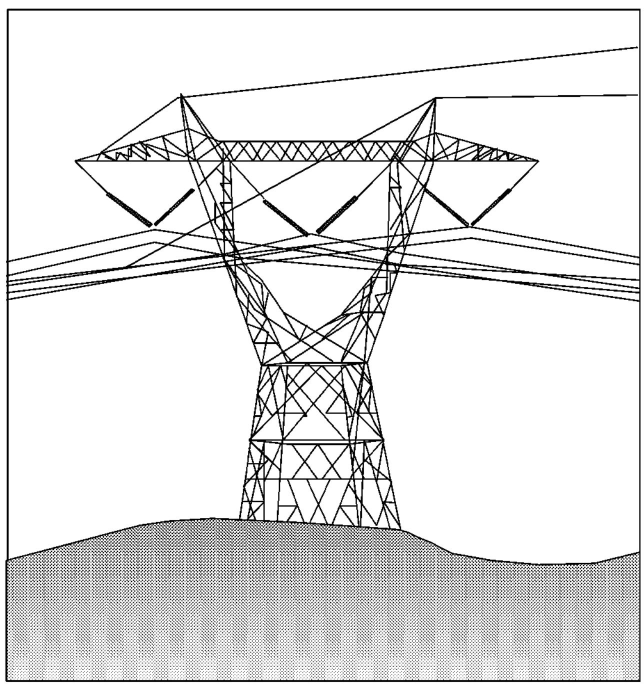
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

2004 INITIAL TRANSMISSION PROPOSAL

REVENUE REQUIREMENT STUDY

TR-04-E-BPA-01



JANUARY 2003

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TABLE OF CONTENTS

APPENDICES

LIST OF TABLES

GRAPHIC PRESENTATIONS

FIGURE

1. INTRODUCTION

1.1 Purpose and Development of the Transmission Revenue Requirement Study

The purpose of the Transmission Revenue Requirement Study (Study) is to establish the level of revenues needed from rates for transmission and ancillary services to recover, in accordance with sound business principles, costs associated with the transmission of electric power over the Federal Columbia River Transmission System (FCRTS). The transmission revenue requirements herein include: recovery of the Federal investment in transmission and transmission-related assets; the operations and maintenance (O&M) and other annual expenses associated with transmission and ancillary services; the cost of generation inputs for ancillary services and other interbusiness-line services necessary for the transmission of power; and all other transmission-related costs incurred by the Administrator.

The cost evaluation period for this rate proposal includes Fiscal Years (FY) 2002 - 2005, the period extending from the last year for which historical information is available through the proposed rate test period. The Study is based on transmission revenue requirements for the rate test period FY 2004 – 2005, including the results of transmission repayment studies. This Study does ***not*** include revenue requirements or a cost recovery demonstration for the Bonneville Power Administration's (BPA) generation function.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine BPA's transmission revenue requirements. Legal requirements are summarized in Chapter 5 of this Study. The Documentation for the Revenue Requirement Study (Documentation) contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment program and its outputs. The Documentation appears in TR-04-E-BPA-01A.

The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of three parts. First, repayment studies for the transmission function are prepared to determine the amortization schedule and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission and transmission-related assets. Repayment studies are conducted for each year of the rate test period, and cover a 35-year repayment period. Second, transmission operating expenses and minimum required net revenues (if needed) are projected for each year of the rate test period. Third, the necessity for including annual planned net revenues for risk is determined taking into account risks, BPA's cost recovery goals, and risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives. *See* Figure 1.1 (page 4) Transmission Revenue Requirement Process.

BPA conducts a current revenue test to determine whether revenues projected from current rates meet its cost recovery requirements and objectives for the rate test and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test, contained in Chapter 4.2 of this study, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the rate test period and the repayment period.

Consistent with RA 6120.2 and the FERC rate review standards applicable to BPA, BPA must demonstrate the adequacy of the proposed rates to recover its costs. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirement and objectives for the rate test and repayment period. The revised revenue test, contained in Chapter 4.3 of this Study, demonstrates that revenues from the proposed transmission and ancillary services rates will recover transmission costs in each year of the rate test period and over the ensuing 35-year repayment period. Consistent with the Treasury payment probability (TPP) standard that was adopted as a long-term policy in 1993, the costs are projected to be recovered through the transmission and ancillary services rates with a greater than 95 percent probability that associated United States (U.S.) Treasury payments will be made on time and in full over the two-year rate period. *See* Chapter 2.2 of this Study.

FIGURE 1.1

TRANSMISSION REVENUE REQUIREMENT PROCESS

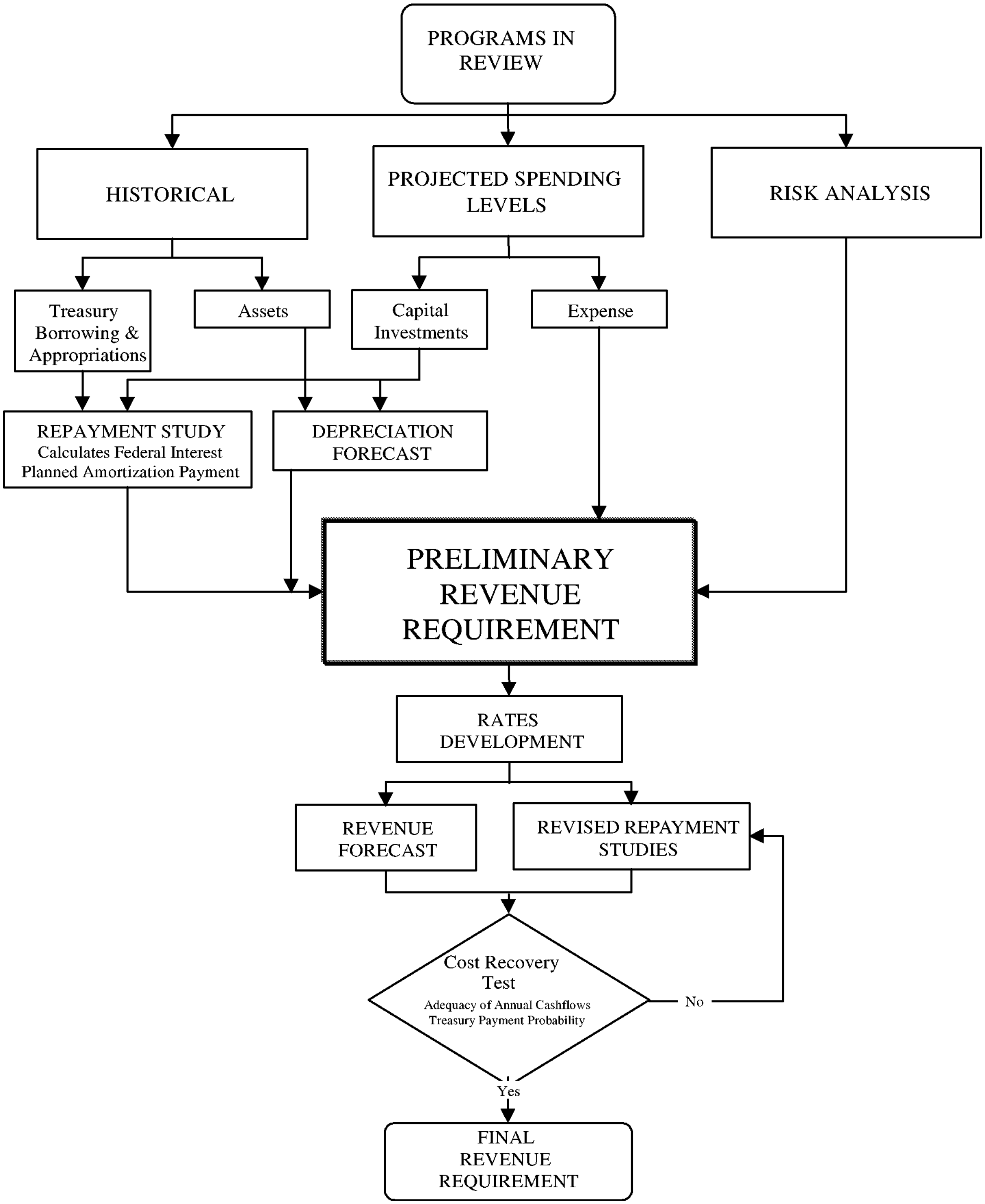


Table 1.1 summarizes the revised revenue test and shows projected net revenues from proposed rates over the two-year rate period. In combination with other risk mitigation tools, these net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives in the face of transmission-related risks.

Table 1.1

PROJECTED NET REVENUES FROM PROPOSED RATES
($000s)

Fiscal Year		Transmission
2004	Projected Revenues From Proposed Rates	$714,016
	Projected Expenses	$697,086
	Net Revenues	**$16,930**
2005	Projected Revenues From Proposed Rates	$735,142
	Projected Expenses	$723,345
	Net Revenues	**$11,797**
Average FYs 2004-2005	**Projected Revenues From Proposed Rates**	**$724,579**
	Projected Expenses	**$710,216**
	Net Revenues	**$14,363**

The TPP for the two year rate period is greater than 95%.

Table 1.2 shows planned transmission repayments to the U.S. Treasury during the rate test period.

Table 1.2

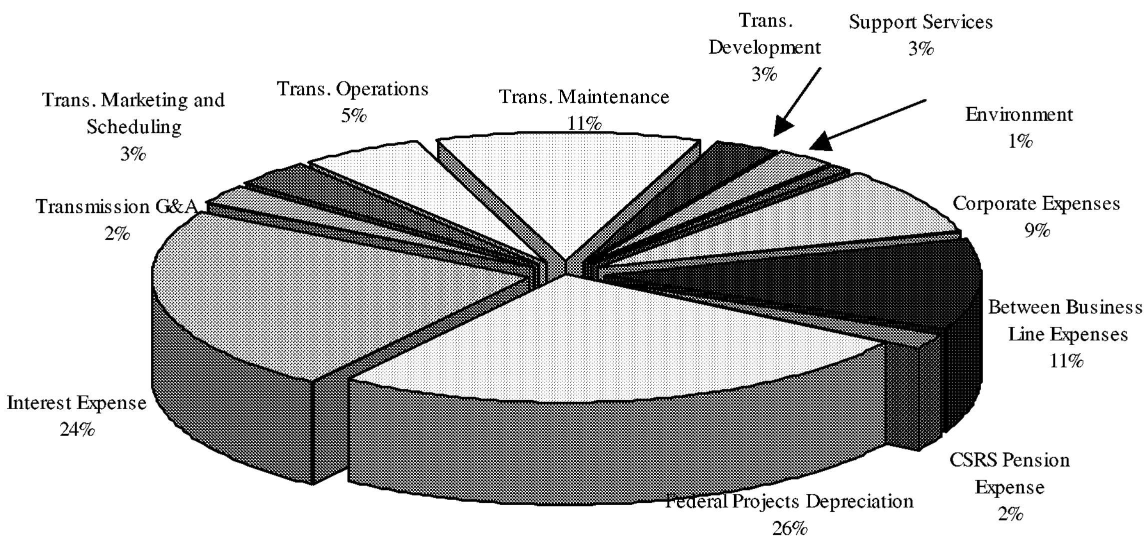
PLANNED REPAYMENTS TO U.S. TREASURY
FYs 2004 – 2005 TRANSMISSION REPAYMENT STUDIES
($000s)

Fiscal Year	Annual Amortization
2004	$151,985
2005	$157,003
Total	$308,988

The transmission operating expenses for FY 2004-2005 included in this proposed revenue requirement appear in Figure 1.2.

Figure 1.2

Composition of Transmission Operating & Interest Expenses
FY 2004-2005 Average



	FY 2004	FY 2005	Average	
		($ in millions)		
Transmission G&A	$ 17.5	$ 17.9	$ 17.7	2%
Transmission Marketing and Scheduling	$ 23.7	$ 24.3	$ 24.0	3%
Transmission System Operations	$ 37.5	$ 38.4	$ 38.0	5%
Transmission System Maintenance	$ 80.0	$ 82.0	$ 81.0	11%
Transmission System Development	$ 18.9	$ 19.3	$ 19.1	3%
Support Services	$ 17.6	$ 18.1	$ 17.9	3%
Environment	$ 4.5	$ 4.6	$ 4.6	1%
Corporate Expenses	$ 61.5	$ 64.0	$ 62.8	9%
Between Business Line Expenses	$ 80.3	$ 80.3	$ 80.3	11%
CSRS Pension Expense	$ 15.5	$ 13.3	$ 14.4	2%
Federal Projects Depreciation	$ 176.5	$ 188.4	$ 182.5	26%
Interest Expense	$ 163.2	$ 172.3	$ 167.8	24%
Total Transmission Expenses	**$ 696.7**	**$ 722.9**	**$ 709.8**	**100%**

1.2 Public Involvement Process

Concurrent with, but independent of preparing this rate proposal, BPA conducted a public process, Programs in Review, to ask customers and constituents for their thoughts about planned capital spending and the expenses associated with supporting a reliable and safe transmission system. The results of these public meetings contributed to the Administrator's decisions on TBL expense and capital spending levels for the FY 2004 2005 rate period. The Administrator's decisions have been reflected in the revenue requirements, including repayment studies, in this rate proposal. *See* Appendix B.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for Spending Levels

The agency's current financial projections for the period FY 2002 through FY 2006 shows BPA with a $1.2 billion revenue and expense gap, cash liquidity problems and limited availability of federal borrowing authority to fund capital investments. Customers participating in Programs In Review and the TBL rate case workshops asked TBL to keep transmission costs and rates low to help offset the effects of the downturn of the Northwest's economy, higher and unstable cost of electrical power and financial uncertainties facing most of their companies or entities. With BPA's projected financial condition and the customer's theme of low costs and rates as guidance, the Transmission Business Line's (TBL) objectives are to manage the business to assure transmission costs are as low as possible consistent with sound business practices, operate a reliable system, and meet the challenges of a competitive market place. The results of these actions will :

(1) Give confidence to BPA customers, tribes, and constituents that transmission system costs are managed effectively and efficiently;

(2) Minimize, if not avoid, transition (stranded) costs associated with integration of new generators; and

(3) Ensure that obligations to the U.S. Treasury and third-party bondholders remain secure.

In July 2002, BPA began a public involvement process entitled "Programs in Review." The purpose of Programs in Review (PIR) was to review and discuss transmission program spending levels for FY 2004 through FY 2006 separate from the rate process. PIR was designed to provide the region an overview and context for major policy issues surrounding TBL's expense and capital programs, and to a lesser degree, various rate case issues such as the treatment of redispatch services and costs. The PIR process helped establish the following goals:

- Assure that rates will not rise, or that they will rise to some minimum level through effective and efficient management of expense and capital program costs
- Assure that there will be no shift in costs or risks with the building of infrastructure projects associated with integration of new generation projects and that those who receive the benefit are being appropriately charged, and
- Manage the transmission system with sufficient resources and program levels to assure transmission system reliability, availability and meet the challenges of a competitive and dynamic market place.

BPA conducted five regional workshops, beginning in July 2002, to ask for customer input during the PIR public process. At the customers' request, an additional workshop was held in Portland in September so staff could provide details of the proposed program levels. The public process solicited customer comments on BPA's proposed FY 2004 through2006 spending levels for transmission system operations, maintenance and construction. Projected costs for FY 2002 and FY 2003 were also presented. This forum included a detailed discussion of capital spending levels and planned transmission system improvements, upgrades and reinforcement projects. In addition to the above, TBL's capital proposal was reviewed through the established Regional Technical Review Teams to better define the prioritization, costs and need for transmission projects. Specifically, TBL identified capital investments that are necessary to:

- Meet existing contractual requirements and increased wholesale transmission transactions, reliably serve load growth, provide reactive needs, new generation reinforcements and system replacements, alleviate constrained paths, and respond to changes in reliability criteria;

- Replace aging equipment and maintain the system in a safe, reliable, environmentally responsible, and cost-effective manner; and
- Invest in technology to address significantly higher and more complex uses of BPA's transmission system

Workshop participants were advised that public comments and concerns offered during the process would inform the Administrator's decision with regard to spending levels. Those spending levels serve as the basis for the revenue requirements, which are then used to set rates. Notices of the workshops were distributed widely to TBL's customers and interested parties and published on BPA's website. Workshop participants provided substantial oral and written comments with regard to BPA's planned transmission capital spending and program expenditures.

The Administrator issued a letter on December 19, 2002, entitled "Close out of the public process and final report on the Transmission Business Line's Programs in Review regarding expense and capital spending – Fiscal Years 2004 and 2005." See Appendix B. The Administrator's decisions have been reflected in the revenue requirements, including repayment studies, in this rate proposal.

The "TBL Expense Levels" table in Appendix B illustrates the initial PIR proposal compared to the final PIR program level decisions. TBL is holding operating cost increases to a level that are less that the rate of inflation. The table includes a $17.5 million annual transmission program reduction of expenses. Significant cost savings are realized in the Transmission general and administrative, operations, maintenance, development and support services programs.

For the capital program, spending levels of $327 million and $280 million are adopted for FY 2004 and FY 2005, respectively. These funding levels do not include funding requirements or risk related to integrating new generation into the transmission system. Integration of new generation is expected to move forward only if non-federal funding were secured.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal which called for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent treasury payment probability (TPP) of making U.S. Treasury payments in full and on time for each two-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision, WP-93-A-02, p. 72. For further discussion of the TPP standard, see the 2002 Final Power Rate Proposal Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 2, Section 2.2, p. 18; and the 2002 Final Power Rate Proposal, Administrator's Record of Decision, WP-02-A-02, pp. 7-7 to 7-16.

In 1996, the Comprehensive Review highlighted the need for a high TPP as part of a strategy to keep the benefits of the federal power system in the region. The Comprehensive Review recommendations were developed with several goals in mind, one of these being to "ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists . . .." At the time of the Comprehensive Review, BPA's 1996 rates supported only an 80 percent probability of meeting Treasury payment in full and on time for the 5-year period.

In this rate proposal, BPA has analyzed its transmission risks and has determined that the Initial Rate Proposal achieves the 95 percent probability standard for the transmission function. A probability at this level satisfies the objectives of the 1993 decision and is in keeping with the

Comprehensive Review recommendation of an improved probability of full repayment to the Treasury.

To achieve this level of TPP, the following risk mitigation “tools” are considered in the rate proposal.

(1) <u>Starting reserves</u> Starting financial reserves include cash in the BPA Treasury Fund and the deferred borrowing balance attributed to the transmission function. The risk-adjusted value for starting reserves is projected to total $162 million at the beginning of FY 2004.

(2) <u>Planned Net Revenues for Risk (PNRR)</u> PNRR is a component of the revenue requirement that is added to annual expenses if reserves are not sufficient for risk mitigation purposes. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short run volatility in costs and revenues and achieve the TPP goal. No PNRR were required to meet the TPP standard in the Initial Rate Proposal.

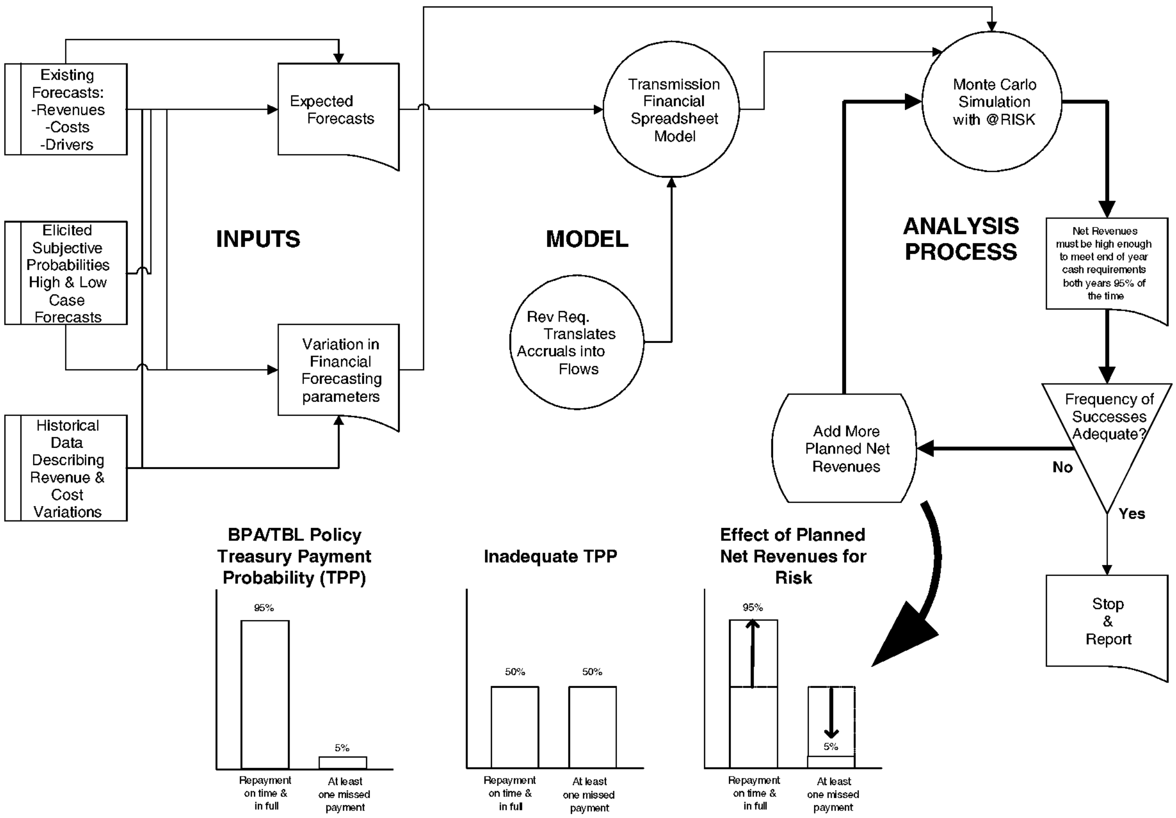
(3) <u>Two-Year Rate Period</u> BPA is proposing to adopt rates for a two-year rate period. The ability to revise rates after two years, or more frequently if need be, serves as an important risk mitigation tool for BPA's transmission function. The impact of a two-year rate period is to limit the effects of uncertainty over an extended time period which must be mitigated by other risk mitigation tools.

2.2.1 Transmission Risk Analysis

To quantify the effects of risk on the finances of BPA's transmission function, BPA analyzes the effects of uncertainty in costs and revenues on transmission cash flows using a Monte Carlo simulation method. *See* Figure 2.1. The analysis is used to estimate the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year cash reserves for the transmission function, after Treasury payments are made, are sufficient to cover the transmission function's working capital requirement of $20 million. The working capital threshold is based on the monthly net cash flow patterns and requirements for the transmission function.

Figure 2.1

Transmission Rate Case Risk Analysis -



The risk analysis is part of the Revenue Requirement Study (RRS). The risk analysis uses data developed in RRS and contributes data to RRS in the form of forecasted cash reserves at the beginning of the FY 2004 to FY2005 rate period and PNRR if reserves are not sufficient to cover risk. Initial input values for point estimates of costs and revenues come from the RRS and the revenue forecast (TR-04-E-BPA-04) and, when combined with inputs describing uncertainty in costs and revenues, provides the basis for the initial estimate of PNRR. The PNRR, in turn, is provided as an expense input to the RRS, changing the transmission revenue requirement and transmission rates. This iterative analysis process is continued until successive estimates of PNRR converge.

The risk analysis covers the period FY2001 through FY 2005. This time frame is used to permit analyzing the change in revenues, costs, and accrual to cash adjustments that are expected to occur between the development of the final rate proposal and the end of the rate period. The advantage to this approach is that cash reserves at the start of the next rate period (FY 2004-2005) may be estimated, including the effects of uncertainty in current rate period cash flows, thus helping define the starting conditions for the next rate period.

2.2.2 Transmission Risk Analysis Model

The foundation of the risk analysis is a transmission financial spreadsheet model. *See* Revenue Requirements Study Documentation, TR-04-E-BPA-01A. This model was developed to estimate the effects of risk and risk mitigation on end-of-year cash reserves and likelihood of successful Treasury payment during the rate period. Cash reserve levels at the end of the fiscal year determine whether BPA is able to meet its Treasury payment obligation. End-of year cash balances during the rate period are, therefore, the main outcome of the model. The model contains individual work sheets including: an input matrix of revenues and costs, an income statement, a cash flow statement, and individual work sheets for variables specified with uncertainty in the model. Parameters for the probability distributions were developed from historical data and analysis of risk factors.

2.3 Capital Funding

BPA transmission capital outlay projections for this proposal are $627.3 million for the FY 2004-2005 rate period. These investments include:

- transmission programs ($594.5 million);

- environmental program ($12.8 million);
- corporate investments in ADP and other capital equipment ($20.0 million).

Revenue requirements reflect the inclusion of $20 million per year as cash requirements to fund capital investments from current revenues.

2.3.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance FY 2004-2005 BPA capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in chapter 6 of the Documentation for Revenue Requirement Study, TR-04-E-BPA-01A.

2.3.2 Federal Appropriations

This Study includes the original capital investments in the Federal transmission system that were financed by Federal appropriations prior to BPA self-financing status. No new investments in the rate period are projected to be funded by appropriations. "The Bonneville Appropriations Refinancing Act" (the Refinancing Act) was enacted in April 1996. This Refinancing Act reset the unpaid principal of FCRPS appropriations and reassigned interest rates. New principal amounts were established at the beginning of FY 1997, at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act there were $1,545.7 million in BPA appropriations outstanding. After the implementation of the Refinancing Act, $1,075.4 million in BPA Appropriations were outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1997-2001 period. Other repayment terms were unaffected.

3. DEVELOPMENT OF REPAYMENT STUDIES

Repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

In this study, as in the previous transmission rate filing, the repayment period has been set at 35 years. This study horizon reflects the fact that the outstanding appropriations and bonds in the transmission system are fully repaid within this period. It also more closely matches the terms of the shorter maturity bonds being issued, and reflects the estimated average service life of plant which is 40 years.

The Revenue Requirement Study includes the results of transmission repayment studies for each of the two years in the rate test period, FYs 2004 and 2005. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations on appropriations and on bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also are included in the repayment study, consistent with the requirements of RA 6120.2. *See* Chapter 5 of this Study.

Historical appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 40 years, taking into account the estimated average service lives for investments and prudent financing and cash management factors. In the repayment studies, all projected bonds have a term of 35 years for transmission investment and 15 years for environment investment. Many bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds also may be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the Treasury. The premium that must be paid decreases with the age of the bond, and is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first. Bonds are issued to finance BPA transmission and environment investments and are repaid within the provisions of each bond agreement with the Treasury.

Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting gross interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period.

Further discussion of the repayment program and repayment program tables is included in this Study at Appendix A; and in Chapter 13 of the Documentation for Revenue Requirement Study, TR-04-E-BPA-01A. *See* Chapter 5 of this Study, for an explanation of repayment policies and requirements.

4. TRANSMISSION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop revenue requirements for FYs 2004 and 2005. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement and Section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash Flows.

4.1 Revenue Requirement Format

For each year of a rate test period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, Planned Net Revenues for Risk, and, if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation.

The Income Statement (Table 4.1A) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 5), Net Interest Expense (Line 14), Minimum Required Net Revenues (Line 16), and Planned Net Revenues for Risk (Line 17). The sum of these four major components is the Total Revenue Requirement (Line 19).

The Minimum Required Net Revenues (Line 16) result from an analysis of the Statement of Cash Flow (Table 4.1B). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the transmission repayment studies.

The Statement of Cash Flow analyzes annual cash inflows and outflows. Cash Provided by Current Operations (Line 8), driven by the Non-cash Expenses shown in Lines 4, 5 and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 12) and Cash From Treasury Borrowing (Line 17). If cash provided by Current Operations are not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least a zero annual Increase in Cash (Line 18). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) then is incorporated in the Income Statement (Line 16).

4.1.1 Income Statement. Below is a line-by-line description of the components in the Income Statement (Table 4.1A). The documentation for the Revenue Requirement Study, TR-04-E-BPA-01A, provides additional information on the development and use of the data contained in the tables.

Operation & Maintenance (Line 2). Operation & Maintenance represents FCRTS O&M expenses incurred by BPA. Specific BPA O&M expenses include transmission scheduling, transmission marketing, transmission system operations, transmission system maintenance, transmission system development, environment, non-Federal transmission arrangements, leases, TBL general and administrative, TBL support services, Civil Service Retirement System pension expense, and corporate administrative and support services. *See* Chapter 2, Documentation, TR-04-E-BPA-01A

Inter-Business Line Expenses (Line 3). Inter-business line expenses, resulting from functional separation and ancillary services products, include the generation inputs to ancillary services from the PBL, station service and remedial action schemes, and the cost of COE and BOR transmission facilities serving the network and utility delivery segments. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Federal Projects Depreciation (Line 4). Depreciation is the annual capital recovery expense associated with FCRTS plant-in-service. BPA transmission and general plant are depreciated by the straight-line method of calculation, using the remaining life technique. *See* Chapter 3, Documentation, TR-04-E -BPA-01A.

Total Operating Expenses (Line 5). Total Operating Expenses is the sum of the above expenses (Lines 2 through 4).

Interest on Appropriated Funds (Line 8). Interest on Appropriated Funds consists of interest on the appropriations BPA received prior to self-financing statusas determined in the transmission repayment studies. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Interest on Long-Term Debt (Line 9). Interest on long-term debt includes interest on bonds that BPA issues to the Treasury to fund investments in transmission plant, environment, general plant supportive of transmission, and capital equipment. Such interest expense is determined in the transmission repayment studies. Any payments of premiums for bonds projected to be amortized are included in this line. Also included is an interest income credit calculated in the transmission repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. A further explanation of the calculation of the interest credit computed within the transmission repayment studies is included in the Appendix. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Interest Credit on Cash Reserves (Line 10). Interest income also is computed on the projected year-end cash balances in the BPA fund attributable to the transmission function that carry over into the next year. It is credited against bond interest. *See* Chapter 4, Documentation, TR-04-E-BPA-01A.

Amortization of Capitalized Bond Premiums (Line 11). When a bond issued to the Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium then is amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Capitalization Adjustment (Line 12). Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations attributed to the transmission function were reduced by $470 million as a result of the refinancing. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Allowance for Funds Used During Construction (AFUDC) (Line 13). AFUDC is a credit against interest on long-term debt (Line 9). This non-cash reduction to interest expense reflects an estimate of interest on the funds used during the construction period of facilities that are not yet in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service.

Net Interest Expense (Line 14). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 8), Interest on Long-Term Debt (Line 9), Interest Credit on Cash Reserves (Line 10), Amortization of Capitalized Bond Premiums (Line 11), Capitalization Adjustment (Line 12), and AFUDC (Line 13).

Total Expenses (Line 15). Total Expenses are the sum of Total Operating Expenses (Line 5) and Net Interest Expense (Line 14).

Minimum Required Net Revenues (Line 16). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 4.1B), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in Section 4.1.2 below.

Planned Net Revenues for Risk (Line 17). Planned Net Revenues for Risk are the amount of net revenues, if any, to be included in rates for financial risk mitigation. There are no Planned Net Revenues for risk included in the Initial Rate Proposal. Starting reserves in FY 2004 are sufficient to mitigate risk in FYs 2004 and 2005.

Total Planned Net Revenues (Line 18). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 16) and Planned Net Revenues for Risk (Line 17).

Total Revenue Requirement (Line 19). Total Revenue Requirement is the sum of Total Expenses (Line 15) and Total Planned Net Revenues (Line 18).

4.1.2 Statement of Cash Flows. Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 4.1B). Documentation, TR-04-E-BPA-01A, provides additional information related to the use and development of the data contained in the table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operations will be sufficient to cover the planned amortization payments (the difference between Lines 12 and 17) without causing the Annual Increase (Decrease) in Cash (Line 18) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 16).

Federal Projects Depreciation (Line 4). Depreciation is from the Income Statement (Table 4.1A, Line 4). It is included in computing Cash Provided By Operations (Line 8) because it is a non-cash expense of the FCRTS.

Amortization of Capitalized Bond Premiums (Line 5). Amortization of Capitalized Bond Premiums, from the Income Statement (Table 4.1A, Line 11), is a non-cash expense.

Capitalization Adjustment (Line 6). The Capitalization Adjustment, from the Income Statement (Table 4.1A, Line 12), is a non-cash (contra) expense.

Accrual Revenues (AC Intertie/Fiber) (Line 7). BPA accounts for the AC Intertie non-Federal capacity ownership lump-sum payments received in FY 1995 as unearned revenues that are recognized as annual accrued revenues over the estimated average service life of BPA's transmission system (straight-line over 40 years). Similarly, some of the leases of fiber optic capacity have included up-front payments, the annual accrued revenues for which are being recognized over the life of the particular contract. The annual accrual revenues, which are part of the total revenues recovering the FCRTS revenue requirement, are included here as a non-cash adjustment to cash from current operations.

Cash Provided By Current Operations (Line 8). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6 and 7, is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 11). Investment in Utility Plant represents the annual increase in capital spending related to additions and replacements to plant-in-service for BPA. *See* Chapter 2 of this Study.

Cash Used for Capital Investments (Line 12). Cash Used for Capital Investments is Line 11.

Increase in Long-Term Debt (Line 14). Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund transmission and capital equipment programs. Also included in this amount may be any notes issued to the U.S. Treasury. Note: projected bonds are reduced to reflect $20 million of revenue financing per year. *See* Chapter 6, Documentation, TR-04-E-BPA-01A.

Repayment of Long-Term Debt (Line 15). Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the repayment studies. *See* Chapter 2, Documentation, TR-04-E-BPA-01A.

Repayment of Capital Appropriations (Line 16). Repayment of Capital Appropriations represents projected amortization of outstanding BPA appropriations (pre self-financing) as determined in the repayment studies. *See* Chapter 2, Documentation, TR-04-E - BPA-01A.

Cash From Treasury Borrowing and Appropriations (Line 17). Cash From Treasury Borrowing and Appropriations is the sum of Lines 14 through 16. This is the net cash flow resulting from increases in cash from new long-term debt and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 18). Annual Increase (Decrease) in Cash, the sum of Lines 8, 12, and 17, reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* discussion above of Minimum Required Net Revenues (Line 2).

Planned Net Revenues For Risk (Line 19). Planned Net Revenues For Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 4.1A, Line 17.)

Total Annual Increase (Decrease) in Cash (Line 20). Total Annual Increase (Decrease) in Cash, the sum of Lines 18 and 19, is the total annual cash that is projected to be available to add to BPA's cash reserves.

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test determines whether the revenues expected from current rates can continue to meet cost recovery requirements.

For the rate test period, the demonstration of the inadequacy of current rates is shown on Tables 4.2A and 4.2B. Table 4.2A is a pro forma income statement for each year. Table 4.2B, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 4.2A (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Line 18). The annual cash flow (Line 18) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. The current revenue test shows that current rates are substantially insufficient to satisfy cost recovery requirements in the rate period.

Table 4.3 shows the inadequacy of current rates to satisfy cost recovery requirements over the 35-year repayment period. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the Net Position results are negative for each year of the rate approval period and in each year of the repayment period.

4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as the Treasury payment probability risk goal for the rate approval period. The revised revenue test was conducted using the forecast of revenues under proposed rates. The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements for the rate approval period of FYs 2004 and 2005.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 4.4A and 4.4B. Table 4.4A presents pro forma income statements for each year.
Table 4.4B, Statements of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 4.4A (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Line 18). The annual cash flow (Line 18) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. To

accommodate the pattern of annual revenues and expenses, $3.5 million of planned amortization was shifted from FY 2004 to FY 2005.

4.4 Repayment Test at Proposed Rates

Table 4.5 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 4.4A and 4.4B) and separate accounting analyses. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate approval period and in each year of the repayment period.

The historical data on this table have been taken from BPA's separate accounting analysis. The rate test period data have been developed specifically for this rate filing. The repayment period data are presented consistent with the requirements of RA 6120.2.

TABLE 4.1A
TRANSMISSION REVENUE REQUIREMENT
INCOME STATEMENT
($thousands)

		A FY 2004	B FY 2005
1	OPERATING EXPENSES		
2	OPERATION AND MAINTENANCE	276,605	281,875
3	INTER-BUSINESS LINE EXPENSES	80,303	80,303
4	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
5	TOTAL OPERATING EXPENSES	533,363	550,564
6	INTEREST EXPENSE		
7	INTEREST ON FEDERAL INVESTMENT -		
8	ON APPROPRIATED FUNDS	63,484	61,499
9	ON LONG-TERM DEBT	162,196	173,048
10	INTEREST INCOME	(23,116)	(23,110)
11	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
12	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
13	AFUDC	(23,583)	(22,474)
14	NET INTEREST EXPENSE	163,182	172,299
15	TOTAL EXPENSES	696,545	722,863
16	MINIMUM REQUIRED NET REVENUES 1/	20,090	7,040
17	PLANNED NET REVENUES FOR RISK	0	0
18	TOTAL PLANNED NET REVENUES	20,090	7,040
19	**TOTAL REVENUE REQUIREMENT**	**716,635**	**729,903**

1/ SEE NOTE ON CASH FLOW TABLE.

TABLE 4.1B
TRANSMISSION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($thousands)

		A	B
		FY 2004	FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUES 1/	20,090	7,040
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	175,485	173,501
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(339,002)	(288,245)
12	CASH USED FOR CAPITAL INVESTMENTS	(339,002)	(288,245)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	319,002	268,245
15	REPAYMENT OF LONG-TERM DEBT	(126,897)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(28,588)	(1)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	163,517	114,744
18	ANNUAL INCREASE (DECREASE) IN CASH	0	0
19	PLANNED NET REVENUES FOR RISK	0	0
20	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0

1/ Line 18 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

TABLE 4.2A
CURRENT REVENUE TEST
INCOME STATEMENT
($thousands)

		A	B
		FY 2004	FY 2005
1	REVENUES FROM CURRENT RATES	703,717	724,145
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	276,605	281,875
4	INTER-BUSINESS LINE EXPENSES	80,303	80,303
5	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
6	TOTAL OPERATING EXPENSES	533,363	550,564
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	63,484	61,499
10	ON LONG-TERM DEBT	162,196	173,048
11	INTEREST CREDIT ON CASH RESERVES	(22,043)	(20,857)
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
13	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
14	AFUDC	(23,583)	(22,474)
15	NET INTEREST EXPENSE	164,255	174,552
16	TOTAL EXPENSES	697,618	725,116
17	NET REVENUES	6,099	(971)

TABLE 4.2B

CURRENT REVENUE TEST

STATEMENT OF CASH FLOWS

($thousands)

		A FY 2004	B FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	6,099	(971)
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	161,494	165,490
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(339,002)	(288,245)
12	CASH USED FOR CAPITAL INVESTMENTS	(339,002)	(288,245)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	319,002	268,245
15	REPAYMENT OF LONG-TERM DEBT	(126,897)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(28,588)	(1)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	163,517	114,744
18	ANNUAL INCREASE (DECREASE) IN CASH	(13,991)	(8,011)
	Cashflow without interest credit on reserves	(36,034)	(28,868)

TABLE 4.3
FEDERAL COLUMBIA RIVER POWER SYSTEM
TRANSMISSION REVENUES FROM CURRENT RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 2/		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 3/		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 /4	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 /5	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	147,665	191,202	59,064		132,138
COST EVALUATION PERIOD											
2002	711,658	358,424		160,600	155,302	37,332	148,470	185,802	131,557		54,245
2003	715,156	347,145		162,987	155,692	49,332	149,725	199,057	142,847		56,210
RATE APPROVAL PERIOD											
2004	703,717	356,908		176,455	164,255	6,099	155,395	141,494 /6	155,485		(13,991)
2005	724,145	362,178		188,386	174,552	(971)	166,461	145,490 /6	153,501		(8,011)

RATE APPROVAL PERIOD											
2004	703,717	356,908		176,455	164,255	6,099	155,395	141,494 /6	155,485		(13,991)
2005	724,145	362,178		188,386	174,552	(971)	166,461	145,490 /6	153,501		(8,011)
REPAYMENT PERIOD											
2006	724,145	362,178	(984)	188,386	158,850	15,715	166,461	182,176	151,450		30,726
2007	724,145	362,178	(1,041)	188,386	155,771	18,851	166,461	185,312	154,586		30,726
2008	724,145	362,178	(1,097)	188,386	153,136	21,542	166,461	188,003	157,277		30,726
2009	724,145	362,178	(1,153)	188,386	151,452	23,282	166,461	189,743	159,017		30,726
2010	724,145	362,178	(1,212)	188,386	149,334	25,459	166,461	191,920	161,194		30,726
2011	724,145	362,178	(1,272)	188,386	147,556	27,297	166,461	193,758	163,032		30,726
2012	724,145	362,178	(1,328)	188,386	146,342	28,567	166,461	195,028	164,302		30,726
2013	724,145	362,178	(1,385)	188,386	144,037	30,929	166,461	197,390	166,664		30,726
2014	724,145	362,178	(1,445)	188,386	141,810	33,216	166,461	199,677	168,951		30,726
2015	724,145	362,178	(1,505)	188,386	143,253	31,833	166,461	198,294	167,568		30,726
2016	724,145	362,178	(1,563)	188,386	146,405	28,739	166,461	195,200	164,474		30,726
2017	724,145	362,178	(1,624)	188,386	144,999	30,206	166,461	196,667	165,941		30,726
2018	724,145	362,178	(1,689)	188,386	143,806	31,464	166,461	197,925	167,199		30,726
2019	724,145	362,178	(1,757)	188,386	142,798	32,540	166,461	199,001	168,275		30,726
2020	724,145	362,178	(1,824)	188,386	142,487	32,918	166,461	199,379	168,653		30,726
2021	724,145	362,178	(1,895)	188,386	142,546	32,930	166,461	199,391	168,665		30,726
2022	724,145	362,178	(1,969)	188,386	142,552	32,998	166,461	199,459	168,733		30,726
2023	724,145	362,178	(2,037)	188,386	137,768	37,850	166,461	204,311	173,585		30,726
2024	724,145	362,178	(2,109)	188,386	143,843	31,847	166,461	198,308	167,582		30,726
2025	724,145	362,178	(2,177)	188,386	144,472	31,286	166,461	197,747	167,021		30,726
2026	724,145	362,178	(2,240)	188,386	145,306	30,515	166,461	196,976	166,250		30,726
2027	724,145	362,178	(2,296)	188,386	146,343	29,534	166,461	195,995	165,269		30,726
2028	724,145	362,178	(2,345)	188,386	142,365	33,561	166,461	200,022	169,296		30,726
2029	724,145	362,178	(2,385)	188,386	147,494	28,472	166,461	194,933	164,207		30,726
2030	724,145	362,178	(2,418)	188,386	151,463	24,536	166,461	190,997	160,271		30,726
2031	724,145	362,178	(2,438)	188,386	153,328	22,691	166,461	189,152	158,426		30,726
2032	724,145	362,178	(2,438)	188,386	150,944	25,075	166,461	191,536	160,810		30,726
2033	724,145	362,178	(2,434)	188,386	150,652	25,363	166,461	191,824	161,098		30,726
2034	724,145	362,178	(2,411)	188,386	152,717	23,275	166,461	189,736	159,008		30,728
2035	724,145	362,178	(2,378)	188,386	156,385	19,574	166,461	186,035	155,309		30,726
2036	724,145	362,178	(2,339)	188,386	158,259	17,661	166,461	184,122	153,396		30,726
2037	724,145	362,178	(2,292)	188,386	161,157	14,716	166,461	181,177	150,449		30,728
2038	724,145	362,178	(2,236)	188,386	164,719	11,098	166,461	177,559	146,829		30,730
2039	724,145	362,178	(2,185)	188,386	172,494	3,272	166,461	169,733	139,007		30,726
2040	724,145	362,178	(2,137)	188,386	175,871	(153)	166,461	166,308	135,582		30,726
TRANSMISSION TOTALS	**38,104,322**	**18,081,107**	**(66,038)**	**9,562,837**	**9,436,137**	**1,090,279**	**8,663,118**	**9,854,397**	**6,451,203**	0	**1,300,553**

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

3/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

5/REDUCED BY $15,000 OF REVENUE FINANCING.

6/REDUCED BY $20,000 OF REVENUE FINANCING.

TABLE 4.4A
REVISED REVENUE TEST
INCOME STATEMENT
($thousands)

		A	B
		FY 2004	**FY 2005**
1	REVENUES FROM PROPOSED RATES	714,016	735,142
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	276,605	281,875
4	INTER-BUSINESS LINE EXPENSES	80,303	80,303
5	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
6	TOTAL OPERATING EXPENSES	533,363	550,564
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	63,484	61,755
10	ON LONG-TERM DEBT	162,196	173,048
11	INTEREST CREDIT ON CASH RESERVES	(22,575)	(22,884)
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
13	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
14	AFUDC	(23,583)	(22,474)
15	NET INTEREST EXPENSE	163,723	172,781
16	TOTAL EXPENSES	697,086	723,345
17	NET REVENUES	16,930	11,797

TABLE 4.4B
REVISED REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2004	B FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	16,930	11,797
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	176,455	188,386
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,713)	(20,115)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	172,325	178,258
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(339,002)	(288,245)
12	CASH USED FOR CAPITAL INVESTMENTS	(339,002)	(288,245)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	319,002	268,245
15	REPAYMENT OF LONG-TERM DEBT	(126,897)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(25,088)	(3,503)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	167,017	111,242
18	ANNUAL INCREASE (DECREASE) IN CASH	340	1,255
	Cashflow without interest credit on reserves	(13,013)	(12,144)

TABLE 4.5
FEDERAL COLUMBIA RIVER POWER SYSTEM
TRANSMISSION REVENUES FROM PROPOSED RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 2/		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 3/		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 /4	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 /5	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	147,665	191,202	59,064		132,138
COST EVALUATION PERIOD											
2002	711,658	358,424		160,600	155,302	37,332	148,470	185,802	131,557		54,245
2003	715,156	347,145		162,987	155,692	49,332	149,725	199,057	142,847		56,210
RATE APPROVAL PERIOD											
2004	714,016	356,908		176,455	163,835	16,818	155,395	152,213 /6	151,985		228
2005	735,142	362,178		188,386	172,900	11,678	166,461	158,139 /6	157,003		1,136

REPAYMENT PERIOD											
2006	735,142	362,178	(984)	188,386	175,192	10,370	166,461	176,831	167,345		9,486
2007	735,142	362,178	(1,041)	188,386	170,954	14,665	166,461	181,126	171,640		9,486
2008	735,142	362,178	(1,097)	188,386	167,075	18,600	166,461	185,061	175,575		9,486
2009	735,142	362,178	(1,153)	188,386	164,059	21,672	166,461	188,133	178,647		9,486
2010	735,142	362,178	(1,212)	188,386	160,519	25,271	166,461	191,732	182,246		9,486
2011	735,142	362,178	(1,272)	188,386	157,215	28,635	166,461	195,096	185,610		9,486
2012	735,142	362,178	(1,328)	188,386	154,359	31,547	166,461	198,008	188,522		9,486
2013	735,142	362,178	(1,385)	188,386	150,309	35,654	166,461	202,115	192,629		9,486
2014	735,142	362,178	(1,445)	188,386	150,340	35,683	166,461	202,144	192,658		9,486
2015	735,142	362,178	(1,505)	188,386	152,402	33,681	166,461	200,142	190,656		9,486
2016	735,142	362,178	(1,563)	188,386	148,953	37,188	166,461	203,649	194,163		9,486
2017	735,142	362,178	(1,624)	188,386	145,652	40,550	166,461	207,011	197,525		9,486
2018	735,142	362,178	(1,689)	188,386	142,868	43,399	166,461	209,860	200,374		9,486
2019	735,142	362,178	(1,757)	188,386	139,810	46,525	166,461	212,986	203,500		9,486
2020	735,142	362,178	(1,824)	188,386	137,179	49,223	166,461	215,684	206,198		9,486
2021	735,142	362,178	(1,895)	188,386	134,826	51,647	166,461	218,108	208,622		9,486
2022	735,142	362,178	(1,969)	188,386	132,141	54,406	166,461	220,867	211,381		9,486
2023	735,142	362,178	(2,037)	188,386	123,876	62,739	166,461	229,200	219,714		9,486
2024	735,142	362,178	(2,109)	188,386	127,551	59,136	166,461	225,597	216,111		9,486
2025	735,142	362,178	(2,177)	188,386	124,964	61,791	166,461	228,252	218,766		9,486
2026	735,142	362,178	(2,240)	188,386	122,377	64,441	166,461	230,902	221,416		9,486
2027	735,142	362,178	(2,296)	188,386	119,790	67,084	166,461	233,545	224,059		9,486
2028	735,142	362,178	(2,345)	188,386	110,848	76,075	166,461	242,536	233,050		9,486
2029	735,142	362,178	(2,385)	188,386	112,272	74,691	166,461	241,152	231,666		9,486
2030	735,142	362,178	(2,418)	188,386	112,184	74,812	166,461	241,273	231,787		9,486
									0		
2031	735,142	362,178	(2,438)	188,386	109,267	77,749	166,461	244,210	234,724		9,486
2032	735,142	362,178	(2,438)	188,386	100,719	86,297	166,461	252,758	243,272		9,486
2033	735,142	362,178	(2,434)	188,386	96,716	90,296	166,461	256,757	247,271		9,486
2034	735,142	362,178	(2,411)	188,386	87,436	99,553	166,461	266,014	256,528		9,486
2035	735,142	362,178	(2,378)	188,386	94,460	92,496	166,461	258,957	249,471		9,486
2036	735,142	362,178	(2,339)	188,386	87,853	99,064	166,461	265,525	256,039		9,486
2037	735,142	362,178	(2,292)	188,386	71,176	115,694	166,461	282,155	272,669		9,486
2038	735,142	362,178	(2,236)	188,386	66,568	120,246	166,461	286,707	277,218		9,489
2039	735,142	362,178	(2,185)	188,386	74,874	111,889	166,461	278,350	268,864		9,486
2040	735,142	362,178	(2,137)	188,386	69,573	117,142	166,461	283,603	274,117		9,486
TRANSMISSION TOTALS	38,510,513	18,081,107	(66,038)	9,562,837	8,577,708	2,354,899	8,663,118	11,119,017	8,435,862	0	580,514

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

3/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

5/REDUCED BY $15,000 OF REVENUE FINANCING.

6/REDUCED BY $20,000 OF REVENUE FINANCING.

5. REVENUE REQUIREMENT LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes:

- the statutory framework that guides the development of BPA's transmission revenue requirement and the recovery of BPA's transmission costs and expenses among the various users of the Federal Columbia River Transmission System (FCRTS), and
- the repayment policies that BPA follows in the development of its revenue requirement.

5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by three main legislative acts: the Flood Control Act of 1944, P.L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act (Transmission System Act) of 1974, P.L. No. 93-454, 88 Stat. 1376; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. No. 96-501, 94 Stat. 2697. Other statutory provisions that guide the development of BPA's revenue requirements include the Federal Power Act, as amended by the Energy Policy Act of 1992 (EPA-92), P.L. No. 102-486. 106 Stat. 2776; and the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, Stat. 132.

DOE Order "Power Marketing Administration Financial Reporting", RA6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment. In addition, from time to time policies issued by the Federal Energy Regulatory Commission (FERC) provide guidance on transmission pricing.

5.1.1 Legal Requirement Governing BPA's Revenue Requirement. BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements thereto as are appropriate and required to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide inter-regional transmission facilities; and (d) maintain the electrical stability and reliability of the Federal system. Section 4 of the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. §838b. The transmission system is built to encourage the widest possible use of all electric energy. Section 5, Flood Control Act, 16 U.S.C. §825s.

BPA's rates must be set in a manner that ensures revenue levels sufficient to recover its costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f (as amended 1977) which provided that:

> *Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the Bonneville project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years.*

This cost recovery principle was repeated for Army reservoir projects in Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s (as amended 1977). In 1974, Section 9 of the Transmission System Act, 16 U.S.C, § 838g, expanded the cost recovery principle so that BPA's rates would be set to also recover:

> *. . . payments provided [in the Administrator's annual budget], and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to [this Act,] and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.*

The Northwest Power Act reiterates and clarifies the cost recovery principle. Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. § 839e(a)(1), provides that:

The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. Such rates shall be established in accordance with Sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. § 838), Section 5 of the Flood Control Act of 1944, and the provisions of this Chapter.

The Northwest Power Act also provides that FERC's confirmation and approval of BPA rates shall assure that the revenue requirement is adequate to recover BPA's costs and ensure timely U.S. Treasury repayments. Section 7(a)(2), 16 U.S.C. § 839e(a)(2), provides:

Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates:

((A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs.

((B) are based upon the Administrator's total system costs; and

((C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. [

More recently, Congress amended the Federal Power Act to allow FERC to order a transmitting utility, including BPA, to provide transmission services (including the enlargement of transmission capacity necessary to provide such services) to an applicant. Section 211(a) of the Federal Power Act, 16 U.S.C. § 824j(a). In applying the Federal Power Act provisions to FERC-ordered transmission service on the FCRTS, section 212(i), 16 U.S.C. § 824k(i)(1)(B), provides that FERC shall assure that *(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and*

> (ii) *the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, and section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential , as determined by the Commission.*

Development of the revenue requirement is a critical component of meeting the statutory cost recovery principles. The costs associated with FCRTS and associated services and expenses, as well as other costs incurred by the Administrator in furtherance of BPA's mission, are included in the Revenue Requirement Study.

5.1.2 The BPA Appropriations Refinancing Act. As in the prior rate period, BPA's transmission rates for the FY 2004 - 2005 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on BPA appropriations ("old capital investments") at the end of FY 1996 be reset at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations absent the Refinancing Act, plus $100 million. 16 U.S.C. § 838l(b). The Refinancing Act also specified that the new principal amounts of the old capital investments be assigned new interest rates from the Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C. §838l(a)(6)(A).

The Refinancing Act restricts prepayment of the new principal for old capital investments to $100 million during the first five years after the effective date of the financing. 16 U.S.C. § 838l(e). The Refinancing Act also specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. 16 U.S.C. §838l(d).

The Refinancing Act also directs the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the Government would not increase the repayment obligations in the future. 16 U.S.C. §838l(i).

5.2 Repayment Requirements and Policies

5.2.1 Separate Repayment Studies. Section 10 of the Transmission System Act, 16 U.S.C. §838h, and section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. §839e(a)(2)(C), provide that the recovery of the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system. In 1982, FERC first directed BPA to provide accounting and repayment statements for its transmission system separate and apart from the accounting and repayment statements for the Federal generation system. *See* 20 FERC ¶61,142 (1982). FERC required BPA to establish books of account for the FCRTS separate from its generation costs; explained that the FCRTS shall be comprised of all investments, including administrative and management costs, related to the transmission of electric power; and directed BPA to develop repayment studies for its transmission function separate from its generation function that set forth the date of each investment, the repayment date and the amount repaid from transmission revenues. *See* 26 FERC ¶ 61,096 (1984). FERC approved BPA's methodology for separate repayment studies in 1984. 28 FERC ¶61,325 (1984).

BPA has prepared separate repayment studies for its transmission and generation functions since 1984. BPA has therefore developed the transmission revenue requirement with no change in this repayment policy.

5.2.2 Repayment Schedules. The statutes applicable to BPA do not include specific directives for scheduling repayment of old capital appropriations and bonds issued to Treasury other than a directive that the Federal investment be amortized over a reasonable period of years. BPA's repayment policy has been established largely through administrative interpretation of its statutory requirements, with Congressional encouragement and occasional admonishment.

There have been a number of changes in BPA's repayment policy over the years concurrent with expansion of the Federal system and changing conditions. In general, current repayment criteria first were approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and submitted to the Secretary and the Federal Power Commission (the predecessor agency to FERC) in support of BPA's rate filing in September 1965.

The repayment policy was presented to Congress for its consideration for the authorization of the Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was discussed in the House of Representatives' Report related to authorization of this project, H.R. Rep. No. 1409, 89th Cong., 2d Sess. 9-10 (1966). As stated in that report:

> *Accordingly, in a repayment study there is no annual schedule of capital repayment. The test of the sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. Hence, repayment may proceed at a faster or slower pace from year-to-year as conditions change.*

This approach to repayment scheduling has the effect of averaging the year-to-year variations in costs and revenues over the repayment period. This results in a uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. It also facilitates the orderly marketing of power and permits BPA's customers, which include both electric utilities and electro-process industries, to plan for the future with assurance.

The Secretary of the Interior issued a statement of power policy on September 30, 1970, setting forth general principles that reaffirmed the repayment policy as previously developed. The most pertinent of these principles was set forth in the Department of the Interior Manual, Part 730, Chapter 1:

> A. *Hydroelectric power, although not a primary objective, will be proposed to Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operation and maintenance costs and interest, in accordance with the law.*
>
> B. *Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment within 50 years with interest that more accurately reflects the cost of money.*

To achieve a greater degree of uniformity in repayment policy for all Federal power marketing agencies, the Deputy Assistant Secretary of the Department of the Interior (DOI) issued a memo on August 2, 1972, outlining: (1) a uniform definition of the commencement of the repayment period for a particular project; (2) the method for including future replacement costs in repayment studies; and (3) a provision that the investment or obligation bearing the highest interest rate shall be amortized first, to the extent possible, while still complying with the prescribed repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo of January 7, 1974, from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the Federal investment or obligations within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for O&M, purchased power, and interest.

On March 22, 1976, the Department of the Interior issued Chapter 4 of Part 730 of the DOI Manual to codify financial reporting requirements for the Federal power marketing agencies. Included therein are standard policies and procedures for preparing system repayment studies.

BPA and other Federal power marketing agencies were transferred to the newly established Department of Energy (DOE) on October 1, 1977. *See* DOE Organization Act, 42 U.S.C. § 7101 et seq. (1994). The DOE adopted the policies set forth in Part 730 of the DOI Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which subsequently was replaced by RA 6120.2 on September 20, 1979, as amended on October 1, 1983.

The repayment policy outlined in DOE Order RA 6120.2, paragraph 12, provides that BPA's total revenues from all sources must be sufficient to:

1. Pay all annual costs of operating and maintaining the Federal system;
2. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements, the cost for transmission services, and other costs during the year in which such costs are incurred;
3. Pay interest expense each year on the unamortized portion of the Federal investment financed with appropriated funds at the interest rates established for each Federal generating project and for each annual increment of such investment in the BPA transmission system, except that recovery of annual interest expense may be deferred in unusual circumstances for short periods of time;
4. Pay when due the interest and amortization portion on outstanding bonds sold to the U.S. Treasury; and
5. Repay:

a. each dollar of power investments and obligations in the Federal generating projects within 50 years after the projects become revenue producing, except as otherwise provided by law;

b. each annual increment of Federal transmission investments and obligations within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; and

c. the cost of each replacement of the Federal system within its service life up to a maximum of 50 years.

While RA 6120.2 allows repayment period of up to 50 years, BPA has set due dates at no more than 40 years to reflect expected service lives of new transmission investment. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Act also contains provisions on repayment periods (due dates) for the refinanced appropriations investments. The Refinancing Act is discussed in section 5.1.2 of this Study.

In addition, other sections within RA 6120.2 require that any outstanding deferred interest payments must be repaid before any planned amortization payments are made. Also, repayments are to be made by amortizing those Federal investments and obligations bearing the highest interest rate first, to the extent possible, while still completing repayment of each increment of Federal investment and obligation within its prescribed repayment period.

APPENDIX A

THE REPAYMENT PROGRAM

1. REPAYMENT PROGRAM OPERATION

1.1. Purpose

The major purpose of the repayment program is to determine, consistent with applicable Federal statutes and policy, whether a given set of annual revenues is sufficient to repay with interest the long-term capital obligations of the FCRTS. The program calculates amortization and interest when determining the minimum revenue level necessary to recover these obligations.

1.2. Computation of Revenues Available for Interest and Amortization

Given a set of revenues and expenses for each year, a set of annual revenues available for interest and amortization can be obtained by subtracting non-investment-related expenses such as O&M expense from revenues (equation 1 below). This revenue subset can then be used to make interest expense and amortization payments on FCRTS-related appropriations and bonds.

(1) $\text{revenues available for interest and amortization}_i =$

$\text{revenues}_i - \text{expenses}_i, \quad i=1,2,\ldots,n,$

where n is the total number of years in the study.

1.3 Computation of Revenues Available for Amortization Payments

For each year, the revenues available for interest and amortization, less interest expense, are used to make amortization payments on the transmission obligations (equation 2 below). The repayment program recognizes the unique nature of each of the Federal investments and associated obligations. The program uses data for all specific investments. The project name, amount of principal, interest rate, in-service date, due date, and the nature of the investment are described for each investment.

(2) revenues available for interest and amortization$_i$ - interest expense$_i$ $= \sum_{j=1}^{m}$ amortization payment$_{ij}$, i=1,2,...n,

$$\text{revenues available for interest and amortization}_i - \text{interest expense}_i = \sum_{j=1}^{m} \text{amortization payment}_{ij}, \quad i=1,2,\ldots n, \tag{2}$$

where m is the total number of Federal investments.

1.4. Computation of Principal Payments Given Due Dates

The amortization payments on each investment must total the investment's principal on or before its due date (equation 3):

$$\sum_{i=1}^{n} \text{payment}_{ij} \leq \text{principal}_j, \quad j=1,2,\ldots m. \tag{3}$$

1.5. Ordering of Payments According to Highest Interest First Constraint

The process described above yields one set of equations in which the payments are summed by year and another set of equations in which the payments are summed by investment. Taken together, however, these two sets of equations have no unique solution. RA 6120.2 provides that "[t]o the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first."

A new equation can be obtained for each year by adding together equation 2 for that year and all earlier years. This equation sums all amortization payments made on any investment that comes due in those years. This equation can be simplified by substituting the principal of each such investment for the sum of the amortization payments on that investment as given by equation 3. The resulting equation (equation 4 below) indicates that for any year the sum of amortization payments on obligations that are not due by that year cannot exceed the sum of the revenues available for interest and amortization less the accumulated interest expense and the accumulated principal of all investments that are due in, or prior to, that year.

$$(4)\quad \sum_{i=1}^{k} \text{revenues available for interest and amortization}_i - \sum_{i=1}^{k} \text{interest expense}_i - \sum_{\text{due}} \text{principal}_j = \sum_{\substack{\text{not}\\\text{due}}} \sum_{i=1}^{k} \text{payment}_{ij}, \qquad k=1,2,\ldots,n.$$

The term "<u>due</u>" refers to Federal obligations due to be repaid in or prior to the year k, and "<u>not due</u>" refers to Federal obligations not due to be repaid by the year k.

For each year in the repayment study, the right side of equation 4 represents the amount of the accumulated amortization payments on Federal obligations that are not due. The left side of the equation represents the accumulated revenues available for making these payments on the Federal obligations. These amortization payments first will be made on the highest interest bearing Federal obligations in compliance with RA 6120.2. If for some future year this amount is evaluated as being zero or negative, then this equation implies that amortization payments can be made only on highest interest bearing Federal obligations that come due on or before that year.

1.6. Iteration Towards A Solution

Equations 2 through 4 do not permit a direct solution. Although the revenues and the Federal obligation that are due are known for all years, an amortization payment made in the current year will affect interest expense in future years. That is, interest expense will no longer have to be paid on the portion of the Federal obligations that has been amortized. This problem is solved using an iterative approach.

The program initially assumes no future interest expense in evaluating the left side of the fourth set of equations. Consequently, the net revenues available for payments on Federal obligations that are not due, but bear the highest interest rates, will be excessive. As payments are determined for each successive year, and the interest expense of a given year is calculated, they are used in the fourth set of equations for all later years. The fourth set of equations is thus modified, and the revenues available for payments on "not due" highest interest rate bearing Federal obligations are reduced. Therefore, the amortization of a Federal obligation on its due date, in order to satisfy equation 3, may violate equation 2. Equation 2 may be violated when a negative balance occurs. A negative balance will result when revenues available for interest and amortization are less than interest expense plus any amortization payments that are due. As a result, a second iteration is necessary.

In the second iteration, the interest expense developed in the first iteration is used in the fourth set of equations for future years. Since amortization payments on "not due" highest interest rate bearing Federal obligations were excessive in the first iteration, the interest expense developed in the first iteration will be less than the true interest expense. These estimates, however, are more accurate than an estimate of zero interest expense and, as a result, the negative balances will be reduced.

If revenues are sufficient to recover a set of annual expenses and to repay with interest BPA's long-term Federal obligations, then the interest expenses of successive iterations will converge and the negative balances will be reduced to zero and thus yield a solution. Under these conditions all four equations will be satisfied.

If revenues are insufficient, then compliance with the fourth set of equations will force amortization payments on the highest interest obligations to be delayed. This will cause an increase in interest expense, leaving less revenue available to amortize high interest obligations. The interest expense from successive iterations will diverge, and the negative balances will start increasing. Under these conditions no solution is possible given available revenues.

BPA does not deliberately plan to defer annual expenses in the future. Therefore, if revenues are insufficient to cover annual expenses for any year of the repayment period, the program decides that no solution is possible at that revenue level.

2. DETERMINING A SUFFICIENT REVENUE LEVEL

As noted above, the repayment program also is used to determine a minimum revenue level sufficient to meet a given set of repayment obligations.

A set of trial revenues can be obtained by multiplying a set of given revenues by a factor. A factor is an assigned real number. If the set of trial revenues obtained with a factor is found to be insufficient, then all lower factors are known to produce insufficient revenues. If some other factor is found to produce sufficient revenues, then all higher factors are known to produce sufficient revenues. Therefore, only intermediate factors need to be tested.

Testing any intermediate factor establishes one of two propositions: (1) that either it and all lower intermediate factors are excluded; or (2) that it and all higher intermediate factors are included. In this manner, the set of intermediate factors is reduced. Through this repeated testing (referred to as the binary search technique), the set of intermediate factors is reduced to a size determined by a preset tolerance limit (the tolerance level of the current study is set at .005 percent of the given revenues).

The lowest factor that is determined to produce sufficient revenues in accordance with this testing procedure will produce the <u>minimum</u> revenue level, within the accuracy of the program, that meets <u>all</u> repayment obligations with interest subject to the conditions specified in RA 6120.2 and relevant legislation.

3. TREATMENT OF BONDS ISSUED TO U.S. TREASURY

BPA's current long-term bonds issued to the Treasury consist of term bonds and callable bonds. The term bonds cannot be prepaid. Their amortization and the revenues required for such bonds are therefore excluded from the above calculations. The remaining bonds are callable bonds and have provisions that allow for early redemption before the maturity date—five years after the date of the issuance on some older bonds and longer periods on some of the more recently issued bonds. In addition, a premium must be paid if a bond is repaid before its due date. The premium that must be paid decreases with the age of the bond. This premium affects the repayment process in two ways.

First, such premiums must be included with the payments of equation 2 and consequently affect the fourth set of equations. The premium that is paid on any Federal bond is considered to be due when the Federal bond is due. The premiums of one iteration are accumulated by due year and included in the fourth set of equations for the following iteration. When each premium is paid in the following iteration, it is used to modify the fourth set of equations and also is accumulated in case another iteration is necessary.

Second, the decrease in the premium that must be paid also affects the highest interest selection process. This effect is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first.

4. INTEREST INCOME

BPA is authorized by applicable legislation and RA 6120.2 to calculate interest income as a credit to interest expense. An interest income credit is computed within the repayment program based on the average cash balance of funds required to be collected for payments to the Treasury in that year. The program assumes that the cash accumulates at a uniform rate throughout the year, except for the semi-annual interest paid on bonds issued to the Treasury. At the end of the year the cash balance together with the interest credit earned thereon is used for payment of interest expense, amortization of the Federal investment and payment of bond premiums.

5. FLOW CHARTS

The following three pages contain flow charts associated with the repayment study program. The first chart shows the binary search process. The second chart shows the test for sufficiency. The third chart shows the application of revenues. *See* Chapter 13 of Documentation for Revenue Requirement Study, TR-04-E-BPA-01A, for further explanation of Repayment Study Program Theory and Operation.

Figure A1

REPAYMENT PROGRAM
(BINARY SEARCH)
CHART 1

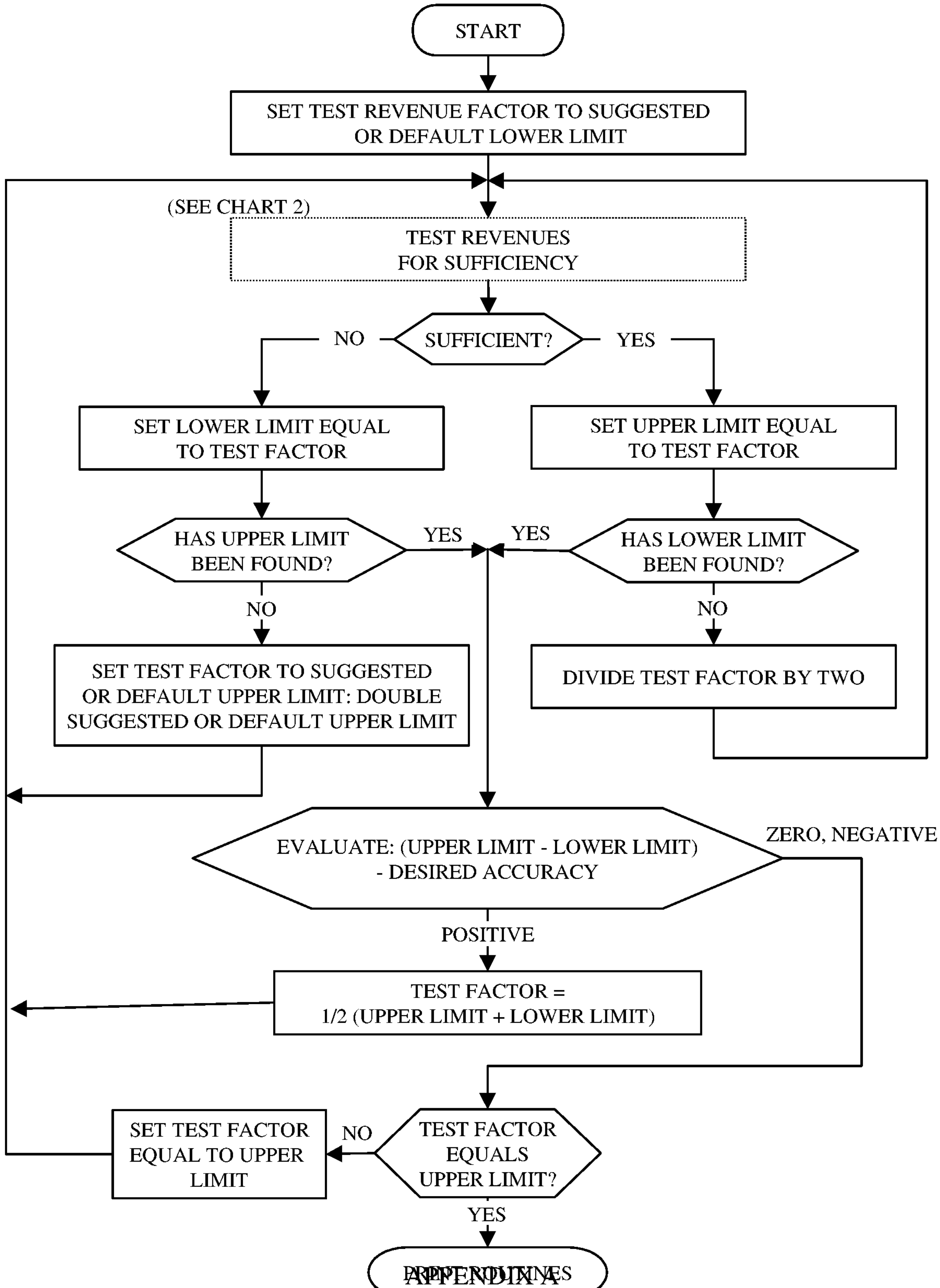


Figure A2

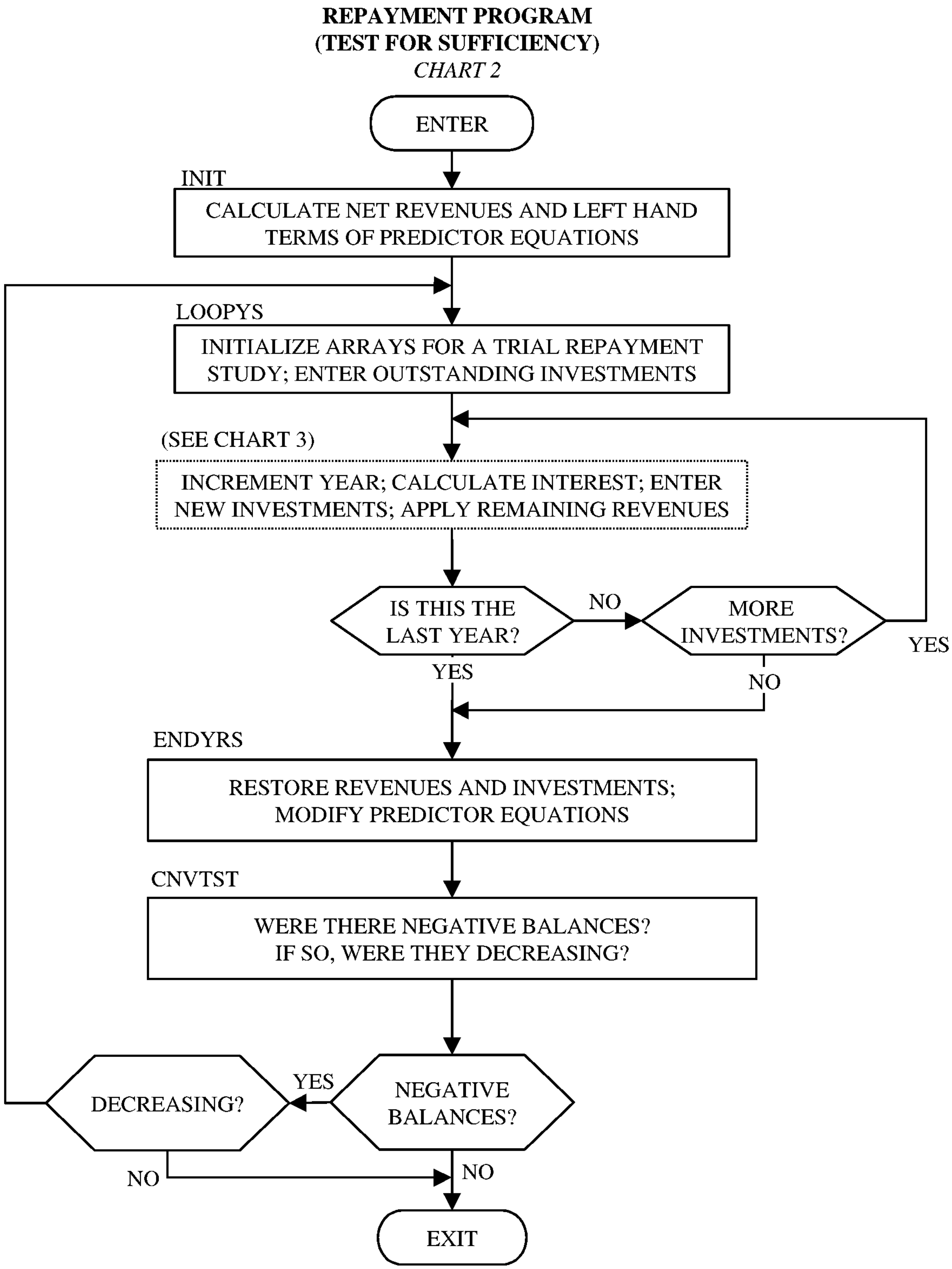
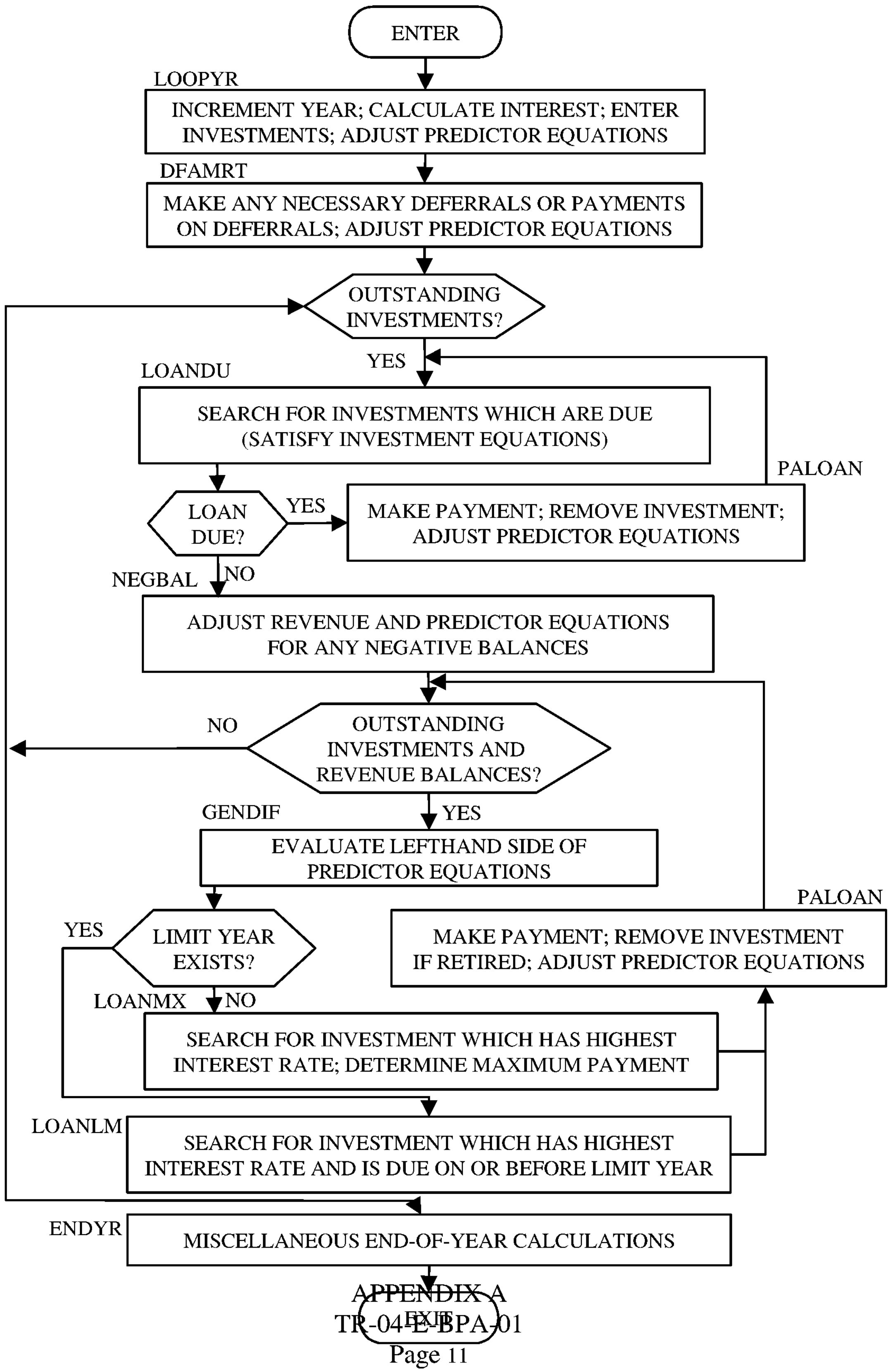

REPAYMENT PROGRAM
(TEST FOR SUFFICIENCY)
CHART 2
ENTER
INIT
CALCULATE NET REVENUES AND LEFT HAND TERMS OF PREDICTOR EQUATIONS
LOOPYS
INITIALIZE ARRAYS FOR A TRIAL REPAYMENT STUDY; ENTER OUTSTANDING INVESTMENTS
(SEE CHART 3)
INCREMENT YEAR; CALCULATE INTEREST; ENTER NEW INVESTMENTS; APPLY REMAINING REVENUES
IS THIS THE LAST YEAR?
NO
MORE INVESTMENTS?
YES
YES
NO
ENDYRS
RESTORE REVENUES AND INVESTMENTS; MODIFY PREDICTOR EQUATIONS
CNVTST
WERE THERE NEGATIVE BALANCES? IF SO, WERE THEY DECREASING?
DECREASING?
YES
NEGATIVE BALANCES?
NO
NO
EXIT

Figure A3

REPAYMENT PROGRAM
(APPLICATION OF REVENUES)
CHART 3



6. DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table A.1 shows the amortization results from the Transmission repayment studies for FYs 2004 and 2005, summarized by year for both due and discretionary bonds and appropriations.

Tables A.2, A through E, and Tables A.3, A through E, show the results of the Transmission repayment studies for FYs 2004 and 2005, respectively, using revenues from current rates. Table A.4 provides the application of amortization through the repayment period for transmission based upon the revenues forecast using current rates.

Tables A.2A and A.3A display the repayment program results for transmission for FYs 2004 and 2005. The first column shows the applicable fiscal year. The second column shows the total investment costs of the transmission projects through the cost evaluation period. *See* Chapter 3 of Documentation for Revenue Requirement Study, TR-04-E-BPA-01A. In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. *See* Chapter 7 of Documentation for Revenue Requirement Study, TR-04-E-BPA-01A. The fourth column shows the cumulative dollar amount of the transmission investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. In these studies all additional plant is assumed to be financed by bonds.

The fifth column displays scheduled amortization payments for transmission for each year of the repayment period. Unamortized transmission obligations, shown in the last column, are determined by taking the previous year's unamortized amount, adding any replacements, and subtracting amortization.

Tables A.2B and A.3B display planned principal payments by fiscal year for Federal transmission obligations. Shown on these tables are the principal payments associated with appropriations and BPA bonds.

Tables A.2C and A.3C show the planned interest payments by fiscal year for Federal transmission obligations. Shown on these tables are the interest payments associated with appropriations and BPA bonds.

Tables A.2D and A.3D show a summary of the Federal transmission principal and interest payments through the repayment period.

Tables A.2E and A.3E compare the schedule of unamortized Federal transmission obligations resulting from the transmission repayment studies to those obligations that are due and must be paid for each year of the repayment period. The Unamortized Investment column shows remaining obligations for each year of the repayment period and is identical to the data shown in the last column of Tables A.2A and A.3A. The Term Schedule column shows obligations that are due for each year. It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. (The total of Unamortized Investment need not be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.)

Table A.4 lists by year through the 35-year repayment period the application of the transmission amortization payments, consistent with the repayment studies, by project. The projected annual amortization payments on the transmission obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

TABLE A.1

TRANSMISSION AMORTIZATION SUMMARY
REVISED REPAYMENT STUDY FOR INITIAL PROPOSAL 2004
FY 2004-2005
(000s)

Maturing/Due		
Bonds		
	2004	98,800
	2005	153,500
		252,300
Appropriations		
	2004	17,020
	2005	0
		17,020
TOTAL DUE		**269,320**

Scheduled But Not Yet Due		
Bonds		
	2004	28,097
	2005	0
		28,097
Appropriations		
	2004	8,068
	2005	3,503
		11,571
TOTAL DUE		**39,668**

Total by Year		
Bonds		
	2004	126,897
	2005	153,500
		280,397
Appropriations		
	2004	25,088
	2005	3,503
		28,591
TOTAL AMORTIZATION	2004	**151,985**
	2005	**157,003**
		308,988

TABLE A.2A

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table B: Transmission Investments Placed in Service (1000s) (FY 2004)

	Investment Placed in Service					
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment
9/30/2001	5,572,252.00	1,066,763.00	6,639,015.00	-	-	6,639,015.00
9/30/2002	272,520.00	-	6,911,535.00	63,913.00	67,644.00	6,779,978.00
9/30/2003	329,965.00	-	7,241,500.00	135,925.00	6,922.00	6,967,096.00
9/30/2004	319,002.00	-	7,560,502.00	115,820.00	36,165.00	7,134,113.00
9/30/2005	-	97,222.00	7,657,724.00	153,500.00	3,503.00	7,074,332.00
9/30/2006	-	101,461.00	7,759,185.00	125,739.00	39,296.35	7,010,757.65
9/30/2007	-	105,750.00	7,864,935.00	135,728.00	33,524.11	6,947,255.54
9/30/2008	-	109,993.00	7,974,928.00	126,213.00	46,898.01	6,884,137.53
9/30/2009	-	114,180.00	8,089,108.00	82,589.00	93,515.04	6,822,213.49
9/30/2010	-	118,393.00	8,207,501.00	116,327.00	63,292.08	6,760,987.41
9/30/2011	-	122,616.00	8,330,117.00	138,240.00	44,651.25	6,700,712.16
9/30/2012	-	126,913.00	8,457,030.00	81,305.00	104,398.38	6,641,921.78
9/30/2013	-	131,268.00	8,588,298.00	76,910.00	112,796.11	6,583,483.67
9/30/2014	-	135,612.00	8,723,910.00	48,920.00	141,868.86	6,528,306.81
9/30/2015	-	139,778.00	8,863,688.00	-	187,726.55	6,480,358.26
9/30/2016	-	143,740.00	9,007,428.00	-	191,055.46	6,433,042.80
9/30/2017	-	147,554.00	9,154,982.00	-	193,933.54	6,386,663.26
9/30/2018	-	151,123.00	9,306,105.00	568.00	196,237.83	6,340,980.43
9/30/2019	-	154,611.00	9,460,716.00	7,369.00	192,609.35	6,295,613.08
9/30/2020	-	158,030.00	9,618,746.00	-	202,457.11	6,251,185.97
9/30/2021	-	161,283.00	9,780,029.00	-	205,219.33	6,207,249.64
9/30/2022	-	164,359.00	9,944,388.00	-	208,042.03	6,163,566.61
9/30/2023	-	167,351.00	10,111,739.00	106,600.00	110,153.99	6,114,163.62
9/30/2024	-	170,193.00	10,281,932.00	-	212,906.44	6,071,450.18
9/30/2025	-	172,752.00	10,454,684.00	-	215,678.37	6,028,523.81
9/30/2026	-	175,073.00	10,629,757.00	-	218,454.54	5,985,142.27
9/30/2027	-	177,189.00	10,806,946.00	-	221,232.59	5,941,098.68
9/30/2028	-	179,070.00	10,986,016.00	112,400.00	118,249.55	5,889,519.13
9/30/2029	-	180,577.00	11,166,593.00	50,000.00	179,226.59	5,840,869.54
9/30/2030	-	181,858.00	11,348,451.00	-	229,388.64	5,793,338.90
9/30/2031	-	182,808.00	11,531,259.00	-	232,532.77	5,743,614.13
9/30/2032	-	183,490.00	11,714,749.00	98,900.00	142,650.46	5,685,553.67
9/30/2033	-	183,915.00	11,898,664.00	110,000.00	135,778.08	5,623,690.59
9/30/2034	-	183,916.00	12,082,580.00	208,400.00	47,078.59	5,552,128.00
9/30/2035	-	183,784.00	12,266,364.00	-	248,135.47	5,487,776.53
9/30/2036	-	183,556.00	12,449,920.00	-	255,132.14	5,416,200.39
9/30/2037	-	183,109.00	12,633,029.00	272,520.00	119.04	5,326,670.35
9/30/2038	-	182,614.00	12,815,643.00	277,467.10	-	5,231,817.25
9/30/2039	-	182,210.00	12,997,853.00	-	268,711.83	5,145,315.42
9/30/2040	-	-	12,997,853.00	-	278,542.43	4,866,772.99
9/30/2041	-	-	12,997,853.00	-	297,441.00	4,569,331.99
Total	6,493,739.00	6,504,114.00	-	2,645,353.10	5,783,167.91	-

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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TABLE A.2B

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table C: Principal Payments (FY 2004)

Date	Transmission Bonds	Transmission Appropriations
9/30/2002	107,644.00	23,913.00
9/30/2003	116,600.00	26,247.00
9/30/2004	126,897.00	25,088.00
9/30/2005	153,500.00	3,503.00
9/30/2006	110,000.00	55,035.35
9/30/2007	111,254.00	57,998.11
9/30/2008	115,300.00	57,811.01
9/30/2009	72,700.00	103,404.04
9/30/2010	90,000.00	89,619.08
9/30/2011	115,000.00	67,891.25
9/30/2012	40,000.00	145,703.38
9/30/2013	-	189,706.11
9/30/2014	106,324.19	84,464.67
9/30/2015	187,726.55	-
9/30/2016	191,055.46	-
9/30/2017	193,933.54	-
9/30/2018	196,805.83	-
9/30/2019	199,978.35	-
9/30/2020	202,457.11	-
9/30/2021	205,219.33	-
9/30/2022	208,042.03	-
9/30/2023	216,753.99	-
9/30/2024	212,906.44	-
9/30/2025	215,678.37	-
9/30/2026	218,454.54	-
9/30/2027	221,232.59	-
9/30/2028	230,649.55	-
9/30/2029	229,226.59	-
9/30/2030	229,388.64	-
9/30/2031	232,532.77	-
9/30/2032	241,550.46	-
9/30/2033	245,778.08	-
9/30/2034	255,478.59	-
9/30/2035	248,135.47	-
9/30/2036	255,132.14	-
9/30/2037	272,639.04	-
9/30/2038	277,467.10	-
9/30/2039	268,711.83	-
9/30/2040	278,542.43	-
9/30/2041	297,441.00	-
Total	7,498,137.01	930,384.00

(1) Net of interest income and AFUDC.

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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TABLE A.2C

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table D: Interest Payments (FY 2004)

Date	Transmission Bonds	Transmission Appropriations
9/30/2002	127,953.37	66,902.97
9/30/2003	136,660.53	65,279.28
9/30/2004	152,973.83	63,483.99
9/30/2005	157,580.00	61,754.57
9/30/2006	154,050.44	61,499.21
9/30/2007	153,848.25	57,540.64
9/30/2008	154,197.53	53,388.46
9/30/2009	155,443.82	49,204.14
9/30/2010	159,491.07	41,699.85
9/30/2011	162,745.82	35,231.93
9/30/2012	164,891.84	30,328.78
9/30/2013	171,479.89	19,794.00
9/30/2014	184,152.94	6,097.19
9/30/2015	193,372.45	-
9/30/2016	190,100.54	-
9/30/2017	187,282.46	-
9/30/2018	184,474.17	-
9/30/2019	181,368.65	-
9/30/2020	178,956.89	-
9/30/2021	176,264.67	-
9/30/2022	173,514.97	-
9/30/2023	164,871.01	-
9/30/2024	168,788.56	-
9/30/2025	166,083.63	-
9/30/2026	163,370.46	-
9/30/2027	160,648.41	-
9/30/2028	151,281.45	-
9/30/2029	152,743.41	-
9/30/2030	152,615.36	-
9/30/2031	149,492.23	-
9/30/2032	140,476.54	-
9/30/2033	136,245.91	-
9/30/2034	126,524.41	-
9/30/2035	133,837.53	-
9/30/2036	126,802.86	-
9/30/2037	109,251.95	-
9/30/2038	104,366.87	-
9/30/2039	113,077.17	-
9/30/2040	101,079.57	-
9/30/2041	82,181.00	-
Total	6,104,542.46	612,205.01

(1) Net of interest income and AFUDC.

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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TABLE A.2D

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table G: Summary of Payments (FY 2004)

Date	Transmission Principal	Transmission Interest	Total Payment
9/30/2002	131,557.00	194,856.34	326,413.34
9/30/2003	142,847.00	201,939.81	344,786.81
9/30/2004	151,985.00	216,457.82	368,442.82
9/30/2005	157,003.00	219,334.57	376,337.57
9/30/2006	165,035.35	215,549.65	380,585.00
9/30/2007	169,252.11	211,388.89	380,641.00
9/30/2008	173,111.01	207,585.99	380,697.00
9/30/2009	176,104.04	204,647.96	380,752.00
9/30/2010	179,619.08	201,190.92	380,810.00
9/30/2011	182,891.25	197,977.75	380,869.00
9/30/2012	185,703.38	195,220.62	380,924.00
9/30/2013	189,706.11	191,273.89	380,980.00
9/30/2014	190,788.86	190,250.13	381,038.99
9/30/2015	187,726.55	193,372.45	381,099.00
9/30/2016	191,055.46	190,100.54	381,156.00
9/30/2017	193,933.54	187,282.46	381,216.00
9/30/2018	196,805.83	184,474.17	381,280.00
9/30/2019	199,978.35	181,368.65	381,347.00
9/30/2020	202,457.11	178,956.89	381,414.00
9/30/2021	205,219.33	176,264.67	381,484.00
9/30/2022	208,042.03	173,514.97	381,557.00
9/30/2023	216,753.99	164,871.01	381,625.00
9/30/2024	212,906.44	168,788.56	381,695.00
9/30/2025	215,678.37	166,083.63	381,762.00
9/30/2026	218,454.54	163,370.46	381,825.00
9/30/2027	221,232.59	160,648.41	381,881.00
9/30/2028	230,649.55	151,281.45	381,931.00
9/30/2029	229,226.59	152,743.41	381,970.00
9/30/2030	229,388.64	152,615.36	382,004.00
9/30/2031	232,532.77	149,492.23	382,025.00
9/30/2032	241,550.46	140,476.54	382,027.00
9/30/2033	245,778.08	136,245.91	382,023.99
9/30/2034	255,478.59	126,524.41	382,003.00
9/30/2035	248,135.47	133,837.53	381,973.00
9/30/2036	255,132.14	126,802.86	381,935.00
9/30/2037	272,639.04	109,251.95	381,890.99
9/30/2038	277,467.10	104,366.87	381,833.97
9/30/2039	268,711.83	113,077.17	381,789.00
9/30/2040	278,542.43	101,079.57	379,622.00
9/30/2041	297,441.00	82,181.00	379,622.00
Total	8,428,521.01	6,716,747.47	15,145,268.48

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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TABLE A.2E

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table H: Summary of Investments Placed in Service (1000s) (FY 2004)

	Generation		Transmission	
Date	Unamortized Investment	Term Schedule	Unamortized Investment	Term Schedule
9/30/2001	-	-	2,824,499.00	5,470,231.00
9/30/2002	-	-	2,965,462.00	5,678,838.00
9/30/2003	-	-	3,152,580.00	5,872,878.00
9/30/2004	-	-	3,319,597.00	6,076,060.00
9/30/2005	-	-	3,259,816.00	6,011,966.00
9/30/2006	-	-	3,196,241.65	5,987,688.00
9/30/2007	-	-	3,132,739.54	5,850,010.00
9/30/2008	-	-	3,069,621.53	5,833,790.00
9/30/2009	-	-	3,007,697.49	5,865,381.00
9/30/2010	-	-	2,946,471.41	5,855,347.00
9/30/2011	-	-	2,886,196.16	5,839,723.00
9/30/2012	-	-	2,827,405.78	5,885,331.00
9/30/2013	-	-	2,768,967.67	5,889,689.00
9/30/2014	-	-	2,713,790.81	5,786,018.00
9/30/2015	-	-	2,665,842.26	5,710,409.00
9/30/2016	-	-	2,618,526.80	5,619,502.00
9/30/2017	-	-	2,572,147.26	5,379,707.00
9/30/2018	-	-	2,526,464.43	5,289,259.00
9/30/2019	-	-	2,481,097.08	5,279,049.00
9/30/2020	-	-	2,436,669.97	5,354,237.00
9/30/2021	-	-	2,392,733.64	5,452,283.00
9/30/2022	-	-	2,349,050.61	5,568,631.00
9/30/2023	-	-	2,299,647.62	5,629,382.00
9/30/2024	-	-	2,256,934.18	5,799,575.00
9/30/2025	-	-	2,214,007.81	5,857,394.00
9/30/2026	-	-	2,170,626.27	6,032,467.00
9/30/2027	-	-	2,126,582.68	6,209,656.00
9/30/2028	-	-	2,075,003.13	6,276,326.00
9/30/2029	-	-	2,026,353.54	6,391,181.00
9/30/2030	-	-	1,978,822.90	6,438,761.00
9/30/2031	-	-	1,929,098.13	6,321,569.00
9/30/2032	-	-	1,871,037.67	5,956,159.00
9/30/2033	-	-	1,809,174.59	5,510,112.00
9/30/2034	-	-	1,737,612.00	5,435,628.00
9/30/2035	-	-	1,673,260.53	5,619,412.00
9/30/2036	-	-	1,601,684.39	5,802,968.00
9/30/2037	-	-	1,512,154.35	5,713,557.00
9/30/2038	-	-	1,417,301.25	5,566,774.00
9/30/2039	-	-	1,330,799.42	5,437,351.00
9/30/2040	-	-	1,052,256.99	5,340,129.00
9/30/2041	-	-	754,815.99	5,238,668.00
Total	-	-	95,950,791.53	236,133,096.00

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

11/25/2002 3:10 PM

TABLE A.3A

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD
2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table B: Transmission Investments Placed in Service (1000s) (FY 2005)

	Investment Placed in Service					
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment
9/30/2001	5,572,252.00	1,066,763.00	6,639,015.00	-	-	6,639,015.00
9/30/2002	272,520.00	-	6,911,535.00	63,913.00	67,644.00	6,779,978.00
9/30/2003	329,965.00	-	7,241,500.00	135,925.00	6,922.00	6,967,096.00
9/30/2004	319,002.00	-	7,560,502.00	115,820.00	36,165.00	7,134,113.00
9/30/2005	273,245.00	-	7,833,747.00	153,500.00	3,503.00	7,250,355.00
9/30/2006	-	103,807.00	7,937,554.00	125,739.00	41,606.21	7,186,816.79
9/30/2007	-	108,279.00	8,045,833.00	135,728.00	35,911.84	7,123,455.95
9/30/2008	-	112,618.00	8,158,451.00	126,213.00	49,361.61	7,060,499.34
9/30/2009	-	116,874.00	8,275,325.00	82,589.00	96,057.83	6,998,726.51
9/30/2010	-	121,121.00	8,396,446.00	116,327.00	65,919.03	6,937,601.48
9/30/2011	-	125,375.00	8,521,821.00	138,240.00	47,370.27	6,877,366.21
9/30/2012	-	129,703.00	8,651,524.00	81,305.00	107,217.39	6,818,546.82
9/30/2013	-	134,116.00	8,785,640.00	76,910.00	115,719.11	6,760,033.71
9/30/2014	-	138,570.00	8,924,210.00	48,920.00	143,737.57	6,705,946.14
9/30/2015	-	142,895.00	9,067,105.00	-	190,655.53	6,658,185.61
9/30/2016	-	147,016.00	9,214,121.00	-	194,162.64	6,611,038.97
9/30/2017	-	150,959.00	9,365,080.00	-	197,525.19	6,564,472.78
9/30/2018	-	154,661.00	9,519,741.00	568.00	199,805.64	6,518,760.14
9/30/2019	-	158,269.00	9,678,010.00	7,369.00	196,130.90	6,473,529.24
9/30/2020	-	161,785.00	9,839,795.00	5,414.00	200,783.86	6,429,116.38
9/30/2021	-	165,153.00	10,004,948.00	-	208,621.70	6,385,647.68
9/30/2022	-	168,352.00	10,173,300.00	-	211,380.58	6,342,619.10
9/30/2023	-	171,466.00	10,344,766.00	106,600.00	113,114.36	6,294,370.74
9/30/2024	-	174,425.00	10,519,191.00	-	216,110.95	6,252,684.79
9/30/2025	-	177,121.00	10,696,312.00	-	218,766.29	6,211,039.50
9/30/2026	-	179,569.00	10,875,881.00	-	221,416.26	6,169,192.24
9/30/2027	-	181,779.00	11,057,660.00	-	224,058.80	6,126,912.44
9/30/2028	-	183,792.00	11,241,452.00	112,400.00	120,650.40	6,077,654.04
9/30/2029	-	185,427.00	11,426,879.00	50,000.00	181,665.84	6,031,415.20
9/30/2030	-	186,813.00	11,613,692.00	-	231,787.23	5,986,440.97
9/30/2031	-	187,877.00	11,801,569.00	-	234,724.20	5,939,593.77
9/30/2032	-	188,698.00	11,990,267.00	98,900.00	144,371.89	5,885,019.88
9/30/2033	-	189,258.00	12,179,525.00	110,000.00	137,270.89	5,827,006.99
9/30/2034	-	189,376.00	12,368,901.00	208,400.00	48,128.36	5,759,854.63
9/30/2035	-	189,377.00	12,558,278.00	-	249,470.75	5,699,760.88
9/30/2036	-	189,279.00	12,747,557.00	-	256,039.04	5,633,000.84
9/30/2037	-	188,986.00	12,936,543.00	272,520.00	149.24	5,549,317.60
9/30/2038	-	188,606.00	13,125,149.00	277,218.14	-	5,460,705.46
9/30/2039	-	188,301.00	13,313,450.00	-	268,864.07	5,380,142.39
9/30/2040	-	188,077.00	13,501,527.00	-	274,116.55	5,294,102.84
9/30/2041	-	-	13,501,527.00	-	284,003.94	5,010,098.90
Total	6,766,984.00	6,734,543.00	-	2,650,518.14	5,840,909.96	-

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)
11/25/2002 3:10 PM

TABLE A.3B

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

:TOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIC

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table C: Principal Payments (FY 2005)

	BPA	
Date	Transmission Bonds	Transmission Appropriations
9/30/2002	107,644.00	23,913.00
9/30/2003	116,600.00	26,247.00
9/30/2004	126,897.00	25,088.00
9/30/2005	153,500.00	3,503.00
9/30/2006	110,000.00	57,345.21
9/30/2007	111,254.00	60,385.84
9/30/2008	115,300.00	60,274.61
9/30/2009	72,700.00	105,946.83
9/30/2010	90,000.00	92,246.03
9/30/2011	115,000.00	70,610.27
9/30/2012	40,000.00	148,522.39
9/30/2013	-	192,629.11
9/30/2014	128,984.86	63,672.71
9/30/2015	190,655.53	-
9/30/2016	194,162.64	-
9/30/2017	197,525.19	-
9/30/2018	200,373.64	-
9/30/2019	203,499.90	-
9/30/2020	206,197.86	-
9/30/2021	208,621.70	-
9/30/2022	211,380.58	-
9/30/2023	219,714.36	-
9/30/2024	216,110.95	-
9/30/2025	218,766.29	-
9/30/2026	221,416.26	-
9/30/2027	224,058.80	-
9/30/2028	233,050.40	-
9/30/2029	231,665.84	-
9/30/2030	231,787.23	-
9/30/2031	234,724.20	-
9/30/2032	243,271.89	-
9/30/2033	247,270.89	-
9/30/2034	256,528.36	-
9/30/2035	249,470.75	-
9/30/2036	256,039.04	-
9/30/2037	272,669.24	-
9/30/2038	277,218.14	-
9/30/2039	268,864.07	-
9/30/2040	274,116.55	-
9/30/2041	284,003.94	-
Total	7,561,044.10	930,384.00

(1) Net of interest income and AFUDC.

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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TABLE A.3C

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table D: Interest Payments (FY 2005)

	BPA	
Date	Transmission Bonds	Transmission Appropriations
9/30/2002	127,953.37	66,902.97
9/30/2003	136,660.53	65,279.28
9/30/2004	152,973.83	63,483.99
9/30/2005	163,563.43	61,754.57
9/30/2006	166,229.58	61,499.21
9/30/2007	166,118.91	57,372.25
9/30/2008	166,566.38	53,046.01
9/30/2009	167,913.36	48,682.81
9/30/2010	172,061.60	40,994.37
9/30/2011	175,416.26	34,335.47
9/30/2012	177,660.97	29,234.64
9/30/2013	184,347.39	18,498.50
9/30/2014	198,283.50	4,593.93
9/30/2015	204,939.47	-
9/30/2016	201,490.36	-
9/30/2017	198,188.81	-
9/30/2018	195,405.36	-
9/30/2019	192,347.10	-
9/30/2020	189,716.14	-
9/30/2021	187,363.30	-
9/30/2022	184,678.42	-
9/30/2023	176,412.64	-
9/30/2024	180,088.05	-
9/30/2025	177,500.71	-
9/30/2026	174,913.74	-
9/30/2027	172,327.20	-
9/30/2028	163,384.59	-
9/30/2029	164,809.16	-
9/30/2030	164,720.77	-
9/30/2031	161,803.80	-
9/30/2032	153,256.11	-
9/30/2033	149,253.11	-
9/30/2034	139,972.64	-
9/30/2035	146,997.25	-
9/30/2036	140,389.96	-
9/30/2037	123,712.76	-
9/30/2038	119,104.75	-
9/30/2039	127,410.93	-
9/30/2040	122,110.45	-
9/30/2041	110,086.06	-
Total	6,578,132.75	605,678.00

(1) Net of interest income and AFUDC.

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

11/25/2002 3:10 PM

TABLE A.3D

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table G: Summary of Payments (FY 2005)

Date	Transmission Principal	Transmission Interest	Total
9/30/2002	131,557.00	194,856.34	326,413.34
9/30/2003	142,847.00	201,939.81	344,786.81
9/30/2004	151,985.00	216,457.82	368,442.82
9/30/2005	157,003.00	225,318.00	382,321.00
9/30/2006	167,345.21	227,728.79	395,074.00
9/30/2007	171,639.84	223,491.16	395,131.00
9/30/2008	175,574.61	219,612.39	395,187.00
9/30/2009	178,646.83	216,596.17	395,243.00
9/30/2010	182,246.03	213,055.97	395,302.00
9/30/2011	185,610.27	209,751.73	395,362.00
9/30/2012	188,522.39	206,895.61	395,418.00
9/30/2013	192,629.11	202,845.89	395,475.00
9/30/2014	192,657.57	202,877.43	395,535.00
9/30/2015	190,655.53	204,939.47	395,595.00
9/30/2016	194,162.64	201,490.36	395,653.00
9/30/2017	197,525.19	198,188.81	395,714.00
9/30/2018	200,373.64	195,405.36	395,779.00
9/30/2019	203,499.90	192,347.10	395,847.00
9/30/2020	206,197.86	189,716.14	395,914.00
9/30/2021	208,621.70	187,363.30	395,985.00
9/30/2022	211,380.58	184,678.42	396,059.00
9/30/2023	219,714.36	176,412.64	396,127.00
9/30/2024	216,110.95	180,088.05	396,199.00
9/30/2025	218,766.29	177,500.71	396,267.00
9/30/2026	221,416.26	174,913.74	396,330.00
9/30/2027	224,058.80	172,327.20	396,386.00
9/30/2028	233,050.40	163,384.59	396,434.99
9/30/2029	231,665.84	164,809.16	396,475.00
9/30/2030	231,787.23	164,720.77	396,508.00
9/30/2031	234,724.20	161,803.80	396,528.00
9/30/2032	243,271.89	153,256.11	396,528.00
9/30/2033	247,270.89	149,253.11	396,524.00
9/30/2034	256,528.36	139,972.64	396,501.00
9/30/2035	249,470.75	146,997.25	396,468.00
9/30/2036	256,039.04	140,389.96	396,429.00
9/30/2037	272,669.24	123,712.76	396,382.00
9/30/2038	277,218.14	119,104.75	396,322.89
9/30/2039	268,864.07	127,410.93	396,275.00
9/30/2040	274,116.55	122,110.45	396,227.00
9/30/2041	284,003.94	110,086.06	394,090.00
Total	8,491,428.10	7,183,810.75	15,675,238.85

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

11/25/2002 3:10 PM

TABLE A.3E

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2004 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC IP - $20m Ref Fin, $3.5m AmShft, 2001 HIST YR (11/25/02)

Table H: Summary of Investments Placed in Service (1000s) (FY 2005)

Date	Unamortized Investment	Term Schedule
9/30/2001	2,824,499.00	5,470,231.00
9/30/2002	2,965,462.00	5,678,838.00
9/30/2003	3,152,580.00	5,872,878.00
9/30/2004	3,319,597.00	6,076,060.00
9/30/2005	3,435,839.00	6,187,989.00
9/30/2006	3,372,300.79	6,166,057.00
9/30/2007	3,308,939.95	6,030,908.00
9/30/2008	3,245,983.34	6,017,313.00
9/30/2009	3,184,210.51	6,051,598.00
9/30/2010	3,123,085.48	6,044,292.00
9/30/2011	3,062,850.21	6,031,427.00
9/30/2012	3,004,030.82	6,079,825.00
9/30/2013	2,945,517.71	6,087,031.00
9/30/2014	2,891,430.14	5,986,318.00
9/30/2015	2,843,669.61	5,913,826.00
9/30/2016	2,796,522.97	5,826,195.00
9/30/2017	2,749,956.78	5,589,805.00
9/30/2018	2,704,244.14	5,502,895.00
9/30/2019	2,659,013.24	5,496,343.00
9/30/2020	2,614,600.38	5,569,872.00
9/30/2021	2,571,131.68	5,671,788.00
9/30/2022	2,528,103.10	5,792,129.00
9/30/2023	2,479,854.74	5,856,995.00
9/30/2024	2,438,168.79	6,031,420.00
9/30/2025	2,396,523.50	6,093,608.00
9/30/2026	2,354,676.24	6,273,177.00
9/30/2027	2,312,396.44	6,454,956.00
9/30/2028	2,263,138.04	6,526,348.00
9/30/2029	2,216,899.20	6,646,053.00
9/30/2030	2,171,924.97	6,698,588.00
9/30/2031	2,125,077.77	6,586,465.00
9/30/2032	2,070,503.88	6,226,263.00
9/30/2033	2,012,490.99	5,785,559.00
9/30/2034	1,945,338.63	5,716,535.00
9/30/2035	1,885,244.88	5,905,912.00
9/30/2036	1,818,484.84	6,095,191.00
9/30/2037	1,734,801.60	6,011,657.00
9/30/2038	1,646,189.46	5,870,866.00
9/30/2039	1,565,626.39	5,747,534.00
9/30/2040	1,479,586.84	5,667,780.00
9/30/2041	1,195,582.90	5,563,973.00

File = TransRC2004-IP.sf-Trans 04RC-IP w/$20 Rev Fin-AmShft (11-25-02)

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Table A.4

Application of Amortization
Transmission
FY 2004 Repayment Study

APPLICATION OF AMORTIZATION (1000S) (FY 2005)

Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Amount Amortized
FY 2002	BONNEVILLE POWER ADMINISTRATION	1957	2002	7,933	7,933	6.790%	No	7,933
FY 2002	BONNEVILLE POWER ADMINISTRATION	1957	2002	15,980	15,980	6.790%	Yes	15,980
FY 2002	BPA PROGRAM	1999	2002	40,000	40,000	6.200%	No	40,000
FY 2002	BPA PROGRAM	1995	2025	49,933	37,663	7.700%	No	2,644
FY 2002	BPA PROGRAM	1995	2025	65,000	65,000	7.700%	No	65,000
SUB-TOTAL		-	-	178,846	166,576	-	Yes	131,557
FY 2003	BPA PROGRAM	2000	2003	15,300	15,300	6.850%	No	15,300
FY 2003	BONNEVILLE POWER ADMINISTRATION	1958	2003	15,593	15,593	6.840%	No	15,593
FY 2003	BONNEVILLE POWER ADMINISTRATION	1958	2003	10,654	10,654	6.840%	Yes	10,654
FY 2003	BPA PROGRAM	2000	2003	40,000	40,000	6.400%	No	40,000
FY 2003	BPA PROGRAM	1996	2003	54,378	54,378	5.900%	No	54,378
FY 2003	BPA PROGRAM	1995	2025	49,933	35,019	7.700%	No	6,922
SUB-TOTAL		-	-	185,858	170,944	-	Yes	142,847
FY 2004	BPA PROGRAM	2000	2004	50,000	50,000	7.000%	No	50,000
FY 2004	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,157	8,157	6.880%	No	8,157
FY 2004	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,863	8,863	6.880%	Yes	8,863
FY 2004	BPA PROGRAM	1997	2004	22,600	22,600	6.800%	No	22,600
FY 2004	BPA PROGRAM	1999	2004	26,200	26,200	5.950%	No	26,200
FY 2004	BONNEVILLE POWER ADMINISTRATION	1960	2005	3,598	3,598	6.910%	No	3,598
FY 2004	BONNEVILLE POWER ADMINISTRATION	1960	2005	4,218	4,218	6.910%	Yes	4,218
FY 2004	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	17,805	7.290%	Yes	252
FY 2004	BPA PROGRAM	1995	2025	49,933	28,097	7.700%	No	28,097
SUB-TOTAL		-	-	191,374	169,538	-	Yes	151,985
FY 2005	BPA PROGRAM	2000	2005	53,500	53,500	7.150%	No	53,500
FY 2005	BPA PROGRAM	1997	2005	80,000	80,000	6.900%	No	80,000
FY 2005	BPA PROGRAM	2001	2005	20,000	20,000	5.650%	No	20,000
FY 2005	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	17,553	7.290%	Yes	3,503
SUB-TOTAL		-	-	171,305	171,053	-	Yes	157,003
FY 2006	BPA PROGRAM	1996	2006	70,000	70,000	7.050%	No	70,000

FY	2006	BONNEVILLE POWER ADMINISTRATION	1961	2006	4,468	4,468	6.950%	No	4,468
FY	2006	BONNEVILLE POWER ADMINISTRATION	1961	2006	11,271	11,271	6.950%	Yes	11,271
FY	2006	BPA PROGRAM	2000	2006	40,000	40,000	6.750%	No	40,000
FY	2006	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,766	17,766	7.290%	Yes	15,505
FY	2006	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,051	12,051	7.290%	No	12,051
FY	2006	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	14,050	7.290%	Yes	14,050
SUB-TOTAL			-	-	173,361	169,606	-	Yes	167,345
FY	2007	BONNEVILLE POWER ADMINISTRATION	1962	2007	19,597	19,597	6.980%	No	19,597
FY	2007	BONNEVILLE POWER ADMINISTRATION	1962	2007	4,877	4,877	6.980%	Yes	4,877
FY	2007	BPA PROGRAM	1997	2007	111,254	111,254	6.650%	No	111,254
FY	2007	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,025	12,025	7.290%	No	12,025
FY	2007	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,766	2,261	7.290%	Yes	2,261
FY	2007	BONNEVILLE POWER ADMINISTRATION	1972	2017	21,170	21,170	7.290%	Yes	14,773
FY	2007	BONNEVILLE POWER ADMINISTRATION	1972	2017	3,980	3,980	7.290%	No	3,980
FY	2007	BONNEVILLE POWER ADMINISTRATION	1972	2017	2,873	2,873	7.290%	Yes	2,873
SUB-TOTAL			-	-	193,542	178,037	-	Yes	171,640
FY	2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,876	4,876	7.020%	No	4,876
FY	2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,330	4,330	7.020%	Yes	4,330
FY	2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	904	904	7.020%	No	904
FY	2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	803	803	7.020%	Yes	803
FY	2008	BPA PROGRAM	1998	2008	75,300	75,300	6.000%	No	75,300
FY	2008	BPA PROGRAM	1998	2008	40,000	40,000	5.750%	No	40,000
FY	2008	BONNEVILLE POWER ADMINISTRATION	1972	2017	29,326	29,326	7.290%	No	29,326
FY	2008	BONNEVILLE POWER ADMINISTRATION	1972	2017	21,170	6,397	7.290%	Yes	6,397
FY	2008	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	16,368	7.280%	No	3,148
FY	2008	BONNEVILLE POWER ADMINISTRATION	1973	2018	10,491	10,491	7.280%	Yes	10,491
SUB-TOTAL			-	-	203,568	188,795	-	Yes	175,575
FY	2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	4,151	4,151	7.060%	No	4,151
FY	2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	5,738	5,738	7.060%	Yes	5,738
FY	2009	BPA PROGRAM	1998	2009	72,700	72,700	6.000%	No	72,700
FY	2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	24,412	7.270%	No	24,390
FY	2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	3,003	3,003	7.270%	Yes	3,003
FY	2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	33,788	7.280%	No	33,788
FY	2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	21,656	21,656	7.280%	Yes	21,656
FY	2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	13,220	7.280%	No	13,220
SUB-TOTAL			-	-	181,816	178,668	-	Yes	178,647

FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	3,706	3,706	7.090%	No	3,706
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	7,248	7,248	7.090%	Yes	7,248
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	5,202	5,202	7.090%	No	5,202
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	10,171	10,171	7.090%	Yes	10,171
FY 2010	BPA PROGRAM	2001	2010	60,000	60,000	6.050%	No	60,000
FY 2010	ENVIRONMENT	2001	2010	30,000	30,000	6.050%	No	30,000
FY 2010	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	64,977	7.270%	No	57,903
FY 2010	BONNEVILLE POWER ADMINISTRATION	1970	2015	7,995	7,995	7.270%	Yes	7,995
FY 2010	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	22	7.270%	No	22
SUB-TOTAL		-	-	213,711	189,321	-	Yes	182,246
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	11,830	11,830	7.130%	No	11,830
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	3,049	3,049	7.130%	Yes	3,049
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	6,647	6,647	7.130%	No	6,647
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	1,714	1,714	7.130%	Yes	1,714
FY 2011	BPA PROGRAM	1998	2011	40,000	40,000	6.200%	No	40,000
FY 2011	BPA PROGRAM	2001	2011	25,000	25,000	5.950%	No	25,000
FY 2011	BPA PROGRAM	2001	2011	50,000	50,000	5.750%	No	50,000
FY 2011	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	7,074	7.270%	No	7,074
FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	20,984	7.270%	Yes	5,907
FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,563	12,563	7.270%	No	12,563
FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	21,826	7.270%	Yes	21,826
SUB-TOTAL		-	-	258,590	200,687	-	Yes	185,610
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	19,003	19,003	7.160%	No	19,003
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	4,566	4,566	7.160%	Yes	4,566
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	14,300	14,300	7.160%	No	14,300
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	3,436	3,436	7.160%	Yes	3,436
FY 2012	ENVIRONMENT	1997	2012	40,000	40,000	6.950%	No	40,000
FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,079	12,079	7.270%	No	12,079
FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	15,077	7.270%	Yes	15,077
FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	32,026	7.250%	No	29,245
FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	21,916	21,916	7.250%	Yes	21,916
FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	17,158	7.250%	No	17,158
FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	11,742	11,742	7.250%	Yes	11,742
SUB-TOTAL		-	-	197,210	191,303	-	Yes	188,522
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	41,070	41,070	7.200%	No	41,070
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	8,076	8,076	7.200%	Yes	8,076
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	23,202	23,202	7.200%	No	23,202

FY 2013 BONNEVILLE POWER ADMINISTRATION	1968	2013	4,562	4,562	7.200%	Yes	4,562
FY 2013 BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	42,237	7.230%	No	42,237
FY 2013 BONNEVILLE POWER ADMINISTRATION	1969	2014	22,537	22,537	7.230%	Yes	22,537
FY 2013 BONNEVILLE POWER ADMINISTRATION	1969	2014	384	384	7.230%	No	384
FY 2013 BONNEVILLE POWER ADMINISTRATION	1969	2014	205	205	7.230%	Yes	205
FY 2013 BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	2,781	7.250%	No	2,781
FY 2013 BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	61,025	7.230%	No	45,363
FY 2013 BONNEVILLE POWER ADMINISTRATION	1976	2021	2,212	2,212	7.230%	Yes	2,212
SUB-TOTAL	-	-	237,536	208,291	-	Yes	192,629
FY 2014 BPA PROGRAM	1999	2014	48,920	48,920	5.900%	No	48,920
FY 2014 BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	15,662	7.230%	No	15,662
FY 2014 BONNEVILLE POWER ADMINISTRATION	1977	2022	3,948	3,948	7.210%	No	3,948
FY 2014 BONNEVILLE POWER ADMINISTRATION	1977	2022	5,380	5,380	7.210%	Yes	5,380
FY 2014 BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	33,702	7.210%	No	33,702
FY 2014 BONNEVILLE POWER ADMINISTRATION	1977	2022	4,981	4,981	7.210%	Yes	4,981
FY 2014 BPA PROGRAM	2004	2039	311,633	311,633	7.180%	No	80,065
SUB-TOTAL	-	-	469,589	424,226	-	Yes	192,658
FY 2015 BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	-0	7.270%	No	-0
FY 2015 BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	-0	7.270%	No	-0
FY 2015 BPA PROGRAM	2004	2039	311,633	231,568	7.180%	No	190,656
SUB-TOTAL	-	-	401,022	231,568	-	No	190,656
FY 2016 BONNEVILLE POWER ADMINISTRATION	1971	2016	17,766	-0	7.290%	Yes	-0
FY 2016 BPA PROGRAM	2004	2039	311,633	40,913	7.180%	No	40,913
FY 2016 BPA PROGRAM	2005	2040	267,831	267,831	7.100%	No	153,250
SUB-TOTAL	-	-	597,230	308,744	-	Yes	194,163
FY 2017 BONNEVILLE POWER ADMINISTRATION	1972	2017	21,170	-0	7.290%	Yes	-0
FY 2017 BPA PROGRAM	2005	2040	267,831	114,581	7.100%	No	114,581
FY 2017 BPA PROGRAM	2006	2041	103,807	103,807	7.100%	Yes	82,944
SUB-TOTAL	-	-	392,808	218,388	-	Yes	197,525
FY 2018 ENVIRONMENT	2003	2018	568	568	6.560%	No	568
FY 2018 BPA PROGRAM	2006	2041	103,807	20,863	7.100%	Yes	20,863
FY 2018 BPA PROGRAM	2007	2042	108,279	108,279	7.100%	Yes	108,279
FY 2018 BPA PROGRAM	2008	2043	112,618	112,618	7.100%	Yes	70,664
SUB-TOTAL	-	-	325,272	242,328	-	Yes	200,374

FY 2019 BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	-0	7.270%	Yes	-0
FY 2019 ENVIRONMENT	2004	2019	7,369	7,369	6.770%	No	7,369
FY 2019 BPA PROGRAM	2008	2043	112,618	41,954	7.100%	Yes	41,954
FY 2019 BPA PROGRAM	2009	2044	116,874	116,874	7.100%	Yes	116,874
FY 2019 BPA PROGRAM	2010	2045	121,121	121,121	7.100%	Yes	37,303
SUB-TOTAL	-	-	378,966	287,318	-	Yes	203,500
FY 2020 BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	-0	7.250%	No	-0
FY 2020 ENVIRONMENT	2005	2020	5,414	5,414	6.690%	No	5,414
FY 2020 BPA PROGRAM	2010	2045	121,121	83,818	7.100%	Yes	83,818
FY 2020 BPA PROGRAM	2011	2046	125,375	125,375	7.100%	Yes	116,966
SUB-TOTAL	-	-	283,936	214,607	-	Yes	206,198
FY 2021 BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	-0	7.230%	No	-0
FY 2021 BPA PROGRAM	2011	2046	125,375	8,409	7.100%	Yes	8,409
FY 2021 BPA PROGRAM	2012	2047	129,703	129,703	7.100%	Yes	129,703
FY 2021 BPA PROGRAM	2013	2048	134,116	134,116	7.100%	Yes	70,509
SUB-TOTAL	-	-	450,219	272,228	-	Yes	208,622
FY 2022 BPA PROGRAM	2013	2048	134,116	63,607	7.100%	Yes	63,607
FY 2022 BPA PROGRAM	2014	2049	138,570	138,570	7.100%	Yes	138,570
FY 2022 BPA PROGRAM	2015	2050	142,895	142,895	7.100%	Yes	9,204
SUB-TOTAL	-	-	415,581	345,072	-	Yes	211,381
FY 2023 BPA PROGRAM	1998	2023	106,600	106,600	5.850%	No	106,600
FY 2023 BPA PROGRAM	2015	2050	142,895	133,691	7.100%	Yes	113,114
SUB-TOTAL	-	-	249,495	240,291	-	Yes	219,714
FY 2024 BPA PROGRAM	2015	2050	142,895	20,577	7.100%	Yes	20,577
FY 2024 BPA PROGRAM	2016	2051	147,016	147,016	7.100%	Yes	147,016
FY 2024 BPA PROGRAM	2017	2052	150,959	150,959	7.100%	Yes	48,518
SUB-TOTAL	-	-	440,870	318,552	-	Yes	216,111
FY 2025 BPA PROGRAM	2017	2052	150,959	102,441	7.100%	Yes	102,441
FY 2025 BPA PROGRAM	2018	2053	154,661	154,661	7.100%	Yes	116,326
SUB-TOTAL	-	-	305,620	257,102	-	Yes	218,766
FY 2026 BPA PROGRAM	2018	2053	154,661	38,336	7.100%	Yes	38,336
FY 2026 BPA PROGRAM	2019	2054	158,269	158,269	7.100%	Yes	158,269
FY 2026 BPA PROGRAM	2020	2055	161,785	161,785	7.100%	Yes	24,812

SUB-TOTAL	-	-	474,715	358,390	-	Yes	221,416
FY 2027 BPA PROGRAM	2020	2055	161,785	136,973	7.100%	Yes	136,973
FY 2027 BPA PROGRAM	2021	2056	165,153	165,153	7.100%	Yes	87,086
SUB-TOTAL	-	-	326,938	302,126	-	Yes	224,059
FY 2028 BPA PROGRAM	1998	2028	112,400	112,400	5.850%	No	112,400
FY 2028 BPA PROGRAM	2021	2056	165,153	78,067	7.100%	Yes	78,067
FY 2028 BPA PROGRAM	2022	2057	168,352	168,352	7.100%	Yes	42,583
SUB-TOTAL	-	-	445,905	358,819	-	Yes	233,050
FY 2029 BPA PROGRAM	1998	2029	50,000	50,000	6.650%	No	50,000
FY 2029 BPA PROGRAM	2022	2057	168,352	125,769	7.100%	Yes	125,769
FY 2029 BPA PROGRAM	2023	2058	171,466	171,466	7.100%	Yes	55,897
SUB-TOTAL	-	-	389,818	347,235	-	Yes	231,666
FY 2030 BPA PROGRAM	2023	2058	171,466	115,569	7.100%	Yes	115,569
FY 2030 BPA PROGRAM	2024	2059	174,425	174,425	7.100%	Yes	116,218
SUB-TOTAL	-	-	345,891	289,994	-	Yes	231,787
FY 2031 BPA PROGRAM	2024	2059	174,425	58,207	7.100%	Yes	58,207
FY 2031 BPA PROGRAM	2025	2060	177,121	177,121	7.100%	Yes	176,517
SUB-TOTAL	-	-	351,546	235,328	-	Yes	234,724
FY 2032 BPA PROGRAM	1998	2032	98,900	98,900	6.700%	No	98,900
FY 2032 BPA PROGRAM	2025	2060	177,121	604	7.100%	Yes	604
FY 2032 BPA PROGRAM	2026	2061	179,569	179,569	7.100%	Yes	143,768
SUB-TOTAL	-	-	455,590	279,073	-	Yes	243,272
FY 2033 BPA PROGRAM	1993	2033	110,000	110,000	6.950%	No	110,000
FY 2033 BPA PROGRAM	2026	2061	179,569	35,801	7.100%	Yes	35,801
FY 2033 BPA PROGRAM	2027	2062	181,779	181,779	7.100%	Yes	101,470
SUB-TOTAL	-	-	471,348	327,580	-	Yes	247,271
FY 2034 BPA PROGRAM	1994	2034	50,000	50,000	7.050%	No	50,000
FY 2034 BPA PROGRAM	1994	2034	50,000	50,000	6.850%	No	50,000
FY 2034 BPA PROGRAM	1994	2034	108,400	108,400	6.850%	No	108,400
FY 2034 BPA PROGRAM	2027	2062	181,779	80,309	7.100%	Yes	48,128
SUB-TOTAL	-	-	390,179	288,709	-	Yes	256,528

FY 2035 BPA PROGRAM	2027	2062	181,779	32,181	7.100%	Yes	32,181
FY 2035 BPA PROGRAM	2028	2063	183,792	183,792	7.100%	Yes	183,792
FY 2035 BPA PROGRAM	2029	2064	185,427	185,427	7.100%	Yes	33,498
SUB-TOTAL	-	-	550,998	401,400	-	Yes	249,471
FY 2036 BPA PROGRAM	2003	2038	329,397	329,397	7.010%	No	52,034
FY 2036 BPA PROGRAM	2029	2064	185,427	151,929	7.100%	Yes	151,929
FY 2036 BPA PROGRAM	2030	2065	186,813	186,813	7.100%	Yes	52,076
SUB-TOTAL	-	-	701,637	668,139	-	Yes	256,039
FY 2037 BPA PROGRAM	2002	2037	272,520	272,520	6.580%	No	272,520
FY 2037 BPA PROGRAM	2003	2038	329,397	277,363	7.010%	No	145
FY 2037 BPA PROGRAM	2030	2065	186,813	134,737	7.100%	Yes	4
SUB-TOTAL	-	-	788,730	684,620	-	Yes	272,669
FY 2038 BPA PROGRAM	2003	2038	329,397	277,218	7.010%	No	277,218
SUB-TOTAL	-	-	329,397	277,218	-	No	277,218
FY 2039 BPA PROGRAM	2004	2039	311,633	0	7.180%	No	0
FY 2039 BPA PROGRAM	2030	2065	186,813	134,732	7.100%	Yes	134,732
FY 2039 BPA PROGRAM	2031	2066	187,877	187,877	7.100%	Yes	134,132
SUB-TOTAL	-	-	686,323	322,609	-	Yes	268,864
FY 2040 BPA PROGRAM	2031	2066	187,877	53,745	7.100%	Yes	53,745
FY 2040 BPA PROGRAM	2032	2067	188,698	188,698	7.100%	Yes	188,698
FY 2040 BPA PROGRAM	2033	2068	189,258	189,258	7.100%	Yes	31,673
SUB-TOTAL	-	-	565,833	431,701	-	Yes	274,117
FY 2041 BPA PROGRAM	2033	2068	189,258	157,585	7.100%	Yes	157,585
FY 2041 BPA PROGRAM	2034	2069	189,376	189,376	7.100%	Yes	126,419
SUB-TOTAL	-	-	378,634	346,961	-	Yes	284,004
GRAND TOTAL	-	-	14,750,807	11,463,145	-	Yes	8,491,428

APPENDIX B

PROGRAMS IN REVIEW CLOSE-OUT LETTER

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

December 19, 2002

In reply refer to: TMC-Ditt-2

Dear Programs in Review Participant:

Subject: Close out of the public process and final report on the Transmission Business Line's Programs In Review regarding expense and capital spending - Fiscal Years 2004 and 2005

This report summarizes Bonneville Power Administration's (BPA) discussions with customers during the Transmission Business Line's (TBL) Programs in Review (PIR) process regarding proposed program level expenditures for Fiscal Years (FY) 2004 and 2005, and includes TBL's program level decisions.

Five regional workshops were held during July 2002 to discuss TBL's proposed capital and expense program levels for these two fiscal years. At the customers' request, an additional workshop was held in Portland, Oregon in September so staff could provide details of the proposed program levels.

During the course of these workshops, TBL continued to evaluate spending levels for both capital and expense programs to be as efficient and cost effective as possible, while still maintaining the program levels required to operate a reliable transmission system and meet the challenges of a competitive marketplace.

The PIR process looked at expense and capital levels for a three-year period covering FY 2004-2006, so that TBL would have the flexibility to set rates for a one, two or three year rate period. A two-year rate period is proposed, so the PIR decisions presented cover two years, FY 2004-2005, of TBL expense and capital spending.

At the initial July PIR workshops, the TBL proposed an average annual expense estimate of $374 million for the FY 2004-2005 period. However, based on discussions with customers and TBL's subsequent internal review, TBL has reduced overall expenses by about $17.5 million annually. The TBL's proposed capital program included spending levels of $327M and $280M for FY2004 and FY2005, respectively.

Reducing spending levels

In the July workshops, TBL demonstrated how we substantially reduced capital and expense spending over the past two years. TBL has made significant progress in continuing to control its spending through management and efficiency efforts. TBL also outlined the issues currently facing the transmission industry and how these issues could drive future costs upward.

Over the past 10 years, TBL has cut back on transmission upgrades and expansions, using innovative technologies and techniques to meet customer needs and market demands. This technology allowed us to absorb growth while still maintaining reliability. But, it also meant that TBL had to accept more risk and push our system harder.

Due to load growth throughout the region and increased transactions enabled by market deregulation, the operating margin we once had is now gone. The system is approaching capacity and significant constraints could begin to affect access to the system.

In the coming years, TBL must look at ways to build new lines and upgrade existing transmission to maintain the transmission system's adequacy, reliability and availability. This must be accomplished in the face of increased regional load growth, congested pathways, a greater number of transactions and the related system improvements required to meet these needs, while working to integrate additional generation into the system.

Capital program

Comments received from customers were helpful to us in finalizing our proposed spending levels for the coming years. Comments were generally supportive of spending for proposed infrastructure improvements to continue to maintain reliability of the transmission system. However, this support was conditioned on receiving an assurance that TBL would manage the risks of building the infrastructure projects as related to reliability and that new generators, who directly benefit from the construction of new infrastructure, would prepay for those improvements to the system. We also received some comments about the need to reduce planned program costs while assigning costs directly to any party who benefits from the planned actions. Other comments questioned rising costs in certain areas, such as implementation of a Regional Transmission Organization (RTO), accommodating deregulation, and shifts in redispatch charges.

During the discussion on program levels, some policy issues arose. One focused on the need for proposed transmission improvements and additions, and specifically asked for clarification on who would pay for transmission investments under various construction scenarios. We were also asked about TBL's policy in relation to non-federal funding for infrastructure. Some comments on this issue had to do with practices already decided by BPA, such as those covered in the TBL's Direct Assignment Guidelines. Other comments addressed whether TBL's list of infrastructure projects was still relevant in today's quickly changing electricity industry and how customers could be assured that there is adequate evaluation of project need.

In response, TBL is continuing to move forward on several of the proposed infrastructure projects for varying reasons. These include three proposed transmission line projects to relieve congestion and maintain reliability of the system: Kangley-Echo Lake 500-kV Transmission Line, Shultz-Hanford Area 500-kV Transmission Line, and Grand Coulee-Bell 500-kV

Transmission Line (Eastern Washington Reinforcement). Work is continuing on two other projects, the installation of the Shultz Series Capacitors and the Celilo modernization project. Both of these projects will reinforce the existing transmission system without building new lines. Two other proposed transmission infrastructure projects to enable integration of new generators would only move forward if non-federal funding was secured. These projects are McNary-John Day 500-kV Transmission Line and the Southwest Washington-Northwest Oregon Reinforcement.

We are presently seeking payments in advance from generators in return for future transmission credits. This approach assures that BPA and the region do not run the risk of having stranded investment if the generators decide to delay or cancel their projects. We will continue to act consistent with FERC's policy as it evolves. We will also continue to monitor the situation to understand how this affects generation construction.

We are continuing to investigate how to effectively integrate non-transmission alternatives into our transmission planning process. Before TBL decides to build a line, we want to make sure we have evaluated all feasible alternatives. This could include non-wire alternatives such as energy efficiency programs, demand reduction initiatives, and pricing strategies, among other options. We are currently seeking input from a regional stakeholders group as part of our normal planning process to determine how to best accomplish this goal. We expect to hold our first discussion in early 2003.

I want to assure you that TBL is committed to identifying regional reliability issues, proposing solutions, and using all available mechanisms to find economic and equitable solutions to maintaining the transmission system. As part of this commitment, TBL will continue to facilitate the regional technical dialogue through the established Regional Technical Review Teams to better define the prioritization, costs and need for transmission projects. Thanks to this effort, TBL and the region have developed an annual review process to update the proposed transmission project list and assist in keeping costs under control.

Expense program levels

TBL is holding operating cost increases to a level that are less than the rate of inflation. In order to keep program levels as low as possible, TBL has cut about $17.5 million per year in operating costs. TBL must also recognize cost increases of $2.3 million associated with adjusted employee benefits loading rates. These changes will result in an average annual operating expense budget of $356.5 million. These cuts will be difficult, but TBL is committed to making reductions in labor, materials, and contracts to achieve the proposed spending levels. By operating program, the changes include:

Transmission System Maintenance	($7.6 million)
Transmission G&A	($5.0 million)
Transmission System Operations	($2.6 million)

Transmission Support Services	($1.8 million)
Transmission System Development	($0.9 million)
Wheeling/Leases	$0.1 million
Transmission Scheduling	($0.2 million)
Transmission Marketing	$0.6 million
Total Reductions	**($17.5 million)**

Participation in RTO West

We received several comments from customers about the level of BPA's involvement in RTO West. We continue to see RTO West as a viable alternative for the future if certain conditions are met, and therefore, will continue to allocate resources at current levels to participate in its formation. The decision on whether to join an RTO will not be made until after a full vetting of the issues in a different public forum. Although one customer suggested BPA wait and let an RTO make all the needed infrastructure improvements, we must continue to meet our obligation to allocate resources to plan and build needed transmission infrastructure. Since we have yet to decide whether BPA would join an RTO, we must continue to make the necessary investments in our system. We are committed to participating in the development of an RTO that works for the Northwest. Toward that goal, we included RTO West costs for FY 2004-2005 at $2.6 million a year.

Issues to be covered in the rate case

Certain issues that were identified during the PIR process such as redispatch expense and revenue financing are considered rate case issues and therefore will be discussed and covered in that forum.

Finalizing TBL program levels

Today TBL faces critical issues:

- Operating and maintaining its aging transmission system
- Building a business framework in a changing environment
- Constructing transmission infrastructure to meet load growth
- Determining contractual reliability and resource integration demands
- Maintaining a skilled and trained workforce
- Access to limited capital borrowing authority.

The proposed TBL capital and expense spending levels for FY 2004-2005 reflect TBL decisions on how we will move forward to resolve these critical issues. Our direction will continue to be influenced by feedback from our customers and constituents. Through the PIR process, you have helped us hone our proposed spending levels and better understand alternatives available to us.

We appreciate your comments and input. We remain committed to these open public processes where ideas can flow freely for the region's benefit. Thank you again for your participation in TBL's PIR process.

Sincerely,

/S/

Stephen J. Wright
Administrator and
Chief Executive Officer

2 Enclosures:
Appendix 1 – TBL Expense Levels – Programs in Review
Appendix 2 – TBL Capital Program – Programs in Review

TBL Expense Levels - Programs In Review ($ in thousands)

Program & Other Operating Costs	Averages Across FY 2004-05		
	Initial PIR	**Final PIR**	**Savings**
Transmission G&A	22,701.3	17,699.3	**(5,002.0)**
CSRS Pension Expense	14,350.0	14,350.0	**0.0**
Transmission Marketing	15,004.1	15,565.5	**561.4**
Transmission Scheduling	8,705.9	8,473.1	**(232.8)**
Transmission System Operations	40,563.0	37,922.8	**(2,640.2)**
Transmission System Maintenance	88,633.8	80,995.6	**(7,638.1)**
Transmission System Development	13,885.4	12,983.9	**(901.5)**
Wheeling/Leases	5,973.8	6,105.4	**131.6**
Environment (Includes Environment Org)	4,538.9	4,551.1	**12.2**
Transmission Support Services	19,603.3	17,854.9	**(1,748.5)**
Total System O & M	**233,959.4**	**216,501.4**	**(17,458.0)**
Between Business Line Expenses			
Ancillary Services	71,495.3	71,495.3	**0.0**
Corps/Bureau/Network/Delivery Facilities	4,084.0	4,084.0	**0.0**
Station Service	1,723.6	1,723.6	**0.0**
Total BBL Expense	**77,302.9**	**77,302.9**	**0.0**
Corporate Expenses			
Legal Support - Expense	2,023.0	2,023.0	**0.0**
Shared Services Costs	37,355.0	37,355.0	**0.0**
Corporate Overhead Distributions	23,360.0	23,360.0	**0.0**
Total Corporate Charges	**62,738.0**	**62,738.0**	**0.0**
Total Transmission Operating Expense	**374,000.3**	**356,542.3**	**(17,458.0)**

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
MAIN GRID				
Project Name				
Puget Sound Area Additions	G-1	2004	7,368.7	0.0
Schultz-Wautoma 500 kV line	G-2	2004	50,138.9	0.0
McNary-John Day 500 kV line	G-3	2004	0.0	0.0
Low Mon-Starbucks 500 kV	G-4	2004	0.0	10,904.7
McNary-Smiths Harbor 500 kV	G-5	2004	0.0	0.0
Schultz 500 KV series caps	G-6	2003	3,000.1	0.0
Echo Lake-Monroe 500 kV	G-8	2007	0.0	5,414.4
Coulee-Bell 500 kV (WOH Ph 1)	G-9	2004	61,255.2	0.0
Line Relocation (Nisqually Reservation)			0.0	0.0
Line Relocations on Tribal Lands			3,158.0	3,248.7
Columbia Falls - Kerr Reconductor			0.0	0.0
Seattle Area 500/230 kV Bank	G-11	2006	0.0	1,082.9
Pearl 500/230 KV bank	G-10	2003	0.0	0.0
Chemawa 230/115 kV Bank			0.0	0.0
Santiam-Bethel Tap 230 Line #2			0.0	0.0
Olympia 230/115KV Bank #3			0.0	0.0
Olympia-Shelton 500KV	G-12	2006	252.6	10,828.9
Fairmount Shunt Cap			0.0	0.0
Shelton-Fairmount 230KV line			0.0	0.0
Hanford-Ost. tap to Big Eddy	G-14	2008	1,052.7	3,248.7
N. Cross Cascades SC 500 KV			0.0	5,414.4
Ponderosa 500/230 KV bk #2			0.0	0.0
North Noxon Reinforcement (WOH Ph1)	G-20	2007	631.6	7,580.2
L Goose-Starbucks 500 kV (WOH Ph2)	G-17	2008	0.0	0.0
Big -Eddy-Ostrander 500KV			0.0	0.0
McNary-Brownlee 230 KV (PNW-ID)	G-19	2006	6,316.1	33,569.5
Hatwai-Lolo 230 kV (PNW-ID)	G-18	2007	0.0	0.0
McNary-Tap on Ashe-Marion 500 kV	G-16	2007	421.1	6,497.3
N. Idaho Reinforcement (Lib-Bonners)	G-15	2007	0.0	584.8
Walla Walla 115/69 Bank Repl			0.0	0.0
Santiam-Chemawa 230 Line#2			0.0	0.0
Other Associated gen Integration			3,158.0	4,331.5
NERC Criteria Compliance			2,105.4	2,165.8
Fire Suppression			0.0	0.0
System Reactive Facilities			5,000.0	5,000.0
Various Additions			5,000.0	5,000.0
Total Main Grid			**148,858.4**	**104,871.7**
AREA & CUSTOMER SERVICE				
Project Name				
Albany-Eugene Rebuild			0.0	0.0
Kitsap Penin Reinf			0.0	0.0
Red Mountain 115 kV Sub			0.0	0.0
Walla Walla 115/69 Bank Repl			0.0	0.0
Franklin Area Reinf (recond)			0.0	0.0
SW Ore Coast (Bandon-Rogue)			315.8	1,840.9
Goshen-Drummond Upgrade&Tx			0.0	0.0
Trentwood 230/115kv bk/line			0.0	0.0
Fairview SVC			0.0	0.0
Vintage Valley			0.0	0.0
Port Angeles SVC			0.0	0.0

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
Harney system 138 kV upgrade			0.0	0.0
Driscoll/Clatsop 230/115KV Tx			0.0	0.0
Longview 230/115-kV Bank #2			105.3	541.4
Redmond 230/115KV Bank #2			0.0	0.0
Palisades-Snake River 115 line			0.0	108.3
Palisades-Goshen 161KV line/TX			1,052.7	4,331.5
East Omak 230/115KV Bank			0.0	0.0
Libby-Bonners Ferry 115 Recond			0.0	0.0
Libby-Troy Line Purchase			0.0	0.0
Minidoka Substation Reguild			0.0	0.0
Victor Tap - Goab Switch			0.0	0.0
Alvey-Eugene 1 & 2 TT Addition			0.0	0.0
Addy Sub - Retire Delivery Facilities			0.0	0.0
Potholes Sub - 115KV Bus Tie Addition			126.3	0.0
Duckabush Sub - Repl. Transf.			0.0	0.0
Hampton Sub - Repl. Transf.			0.0	0.0
Vintage Valley- 230 & 115 KV Term. Add.			0.0	0.0
Red Mtn.- 2-115 KV Terminal Add.			1,052.7	0.0
McNary Sub - 115 KV Term. (Benton PUD)			421.1	0.0
Metering Data Upgrade - BPA System			1,052.7	0.0
White Bluffs-Richland -relocate 1 mile			105.3	0.0
substation X (U.S. Navy)			0.0	0.0
Misc. Line Upgrade/Cap Additions for Wind Projects			4,210.7	3,032.1
Customer Service Items			2,947.5	3,248.7
Total Area & Customer Srvc			**11,074.1**	**11,262.0**
UPGRADES & ADDITIONS				
Project Name				
System Controls			10,526.8	12,994.6
Business System Develop.			8,474.0	8,663.1
Trans. System IT Develop.			4,210.7	5,414.4
Ftathead Valley Reinf (RAS)			0.0	0.0
Fiber Optics (Incls Terminations)			13,684.8	12,994.6
Misc Line & Sub Additions			3,158.0	3,248.7
Total Upgrades & Additions			**40,054.3**	**43,315.5**
SYSTEM REPLACEMENTS				
Project Name				
Nonelectric Plant Replcmts			6,316.1	6,497.3
Transmission Line Replcmts			0.0	0.0
Substation Replcmts			0.0	0.0
System Protection Replcmts			0.0	0.0
Pwr Sys Cntrl Replcmts			0.0	0.0
Total M3C, M4C, M5C, M6C			13,684.8	12,994.6
Celilo upgrades	G-7	2003	6,642.4	0.0
Tools and Equipment			5,500.0	5,000.0
Emergency Funds			10,000.0	10,000.0
Total System Replacements			**42,143.2**	**34,492.0**
ENVIRONMENT				

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
Project Name				
PP&A--Fire Prot/Sec Contain				0.0
PP&A--PCB Capacitor Replac				0.0
PP&A--Restoration				0.0
Total VR2C, VR4C, VR7C			7,368.7	5,414.4
Cap ADP Equip--Environment			0.0	0.0
Total Environment (PP&A)			**7,368.7**	**5,414.4**
ALL OTHER DIRECT CAPITAL				
Project Name				
Capital ADP Equipment			736.9	758.0
Completion of Prior Yr Items			100.0	100.0
Cap-to-Exp Adjustments			(3,000.0)	(3,000.0)
Undistributed Funding (Reduction)			0.0	0.0
Total All Other Capital			**(2,163.1)**	**(2,142.0)**
SUB TOTAL TBL CAPITAL (DIRECT)			**247,651.4**	**199,054.5**
INDIRECTS				
TSD Program Indirect			20,802.4	21,322.4
TSD MS&A			8,405.0	8,615.1
Support Services Cap Distribution			10,086.0	10,338.2
Total TBL Indirects			**39,293.4**	**40,275.7**
AFUDC				
AFUDC			22,957.0	23,148.0
Total AFUDC			**22,957.0**	**23,148.0**
CORPORATE OVERHEAD 1/				
Corporate Distributions			7,080.0	7,300.0
Corporate Shared Services			9,910.0	10,380.0
Corporate Legal Support			98.2	100.7
Total Corporate Overhead			**17,088.2**	**17,780.7**
SUB TOTAL TBL CAPITAL (INDIRECT)			**79,338.6**	**81,204.4**
TOTAL TBL CAPITAL			**326,990.0**	**280,258.9**
Non-Borrowing Authority Items				
Plant Funded from Revenues				
Paul-Troutdale 500 kV	G-13	2005	51,581.1	54,761.6
McNary-Smiths Harbor 500 kV	G-5	2004	9,474.1	0.0
McNary-John Day 500 kV line	G-3	2004	47,370.4	0.0
Total Plant Funded from Revenues			**108,425.5**	**54,761.6**
Projects Funded in Advance			20,000.0	20,000.0
Smiths Harbor Sub/Line			5,600.0	0.0
Retirements/Sale of Facilities			5,000.0	5,000.0
Total Non-Borrowing Authority Items			**30,600.0**	**25,000.0**
TOTAL TBL CAPITAL			**466,015.5**	**360,020.5**

Bonneville Power Administration

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